**Commonwealth of Kentucky**
**Division for Air Quality**

# *STATEMENT OF BASIS / SUMMARY*

Title V / PSD; Construction / Operating
Permit: V-26-012

EKPC – John Sherman Cooper Power Station
670 Power Plant Rd
Somerset, KY 42501

July 9, 2026
Michael Baidy & Kayla Thurman, Reviewers

| | |
|---|---|
| SOURCE ID: | 21-199-00005 |
| AGENCY INTEREST: | 3808 |
| ACTIVITY: | APE20250001, APE20250002 |

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## SECTION 1 – SOURCE DESCRIPTION

SIC Code and description: 4911, Electric Services (fossil fuel power generation)

Single Source Det. ☐ Yes ☒ No If Yes, Affiliated Source AI:

Source-wide Limit ☒ Yes ☐ No If Yes, See Section 4, Table A

28 Source Category ☒ Yes ☐ No If Yes, Category: Fossil-fuel boilers, or combination of fossil-fuel boilers, totaling more than 250 million BTUs per hour heat input

County: Pulaski
Nonattainment Area ☒ N/A ☐ $PM_{10}$ ☐ $PM_{2.5}$ ☐ CO ☐ $NO_X$ ☐ $SO_2$ ☐ Ozone ☐ Lead
If yes, list Classification:

PTE* greater than 100 tpy for any criteria air pollutant ☒ Yes ☐ No
If yes, for what pollutant(s)?
☒ $PM_{10}$ ☒ $PM_{2.5}$ ☒ CO ☒ $NO_X$ ☒ $SO_2$ ☒ VOC

PTE* greater than 250 tpy for any criteria air pollutant ☒ Yes ☐ No
If yes, for what pollutant(s)?
☒ $PM_{10}$ ☒ $PM_{2.5}$ ☒ CO ☒ $NO_X$ ☒ $SO_2$ ☒ VOC

PTE* greater than 10 tpy for any single hazardous air pollutant (HAP) ☒ Yes ☐ No
If yes, list which pollutant(s): Ammonia, Hexane; N-Hexane, Hydrochloric Acid, Hydrogen Bromide, Sulfuric Acid

PTE* greater than 25 tpy for combined HAP ☒ Yes ☐ No

*PTE does not include self-imposed emission limitations.

<u>Description of Facility</u>:
East Kentucky Power Cooperative operates the John Sherman Cooper Power Station (EKPC Cooper or Cooper Station) in Pulaski County, Kentucky. The plant currently hosts a generating capacity of 341 MW. After completion of the Cooper Project, the site will have an additional 745 MW of generating capacity.

EKPC Cooper is an electric generating power plant that was commissioned in 1965 and is considered a major stationary source under the Title V Operating Permit program, Prevention of Significant Deterioration (PSD) program, and National Emissions Standards for Hazardous Air Pollutants (NESHAP). As a result, all major modifications at the facility are subject to the provisions of 401 KAR 51:017, *Prevention of significant deterioration of air quality*. Additionally, as a fossil fuel-fired steam electric plant of more than 250 MMBtu per hour heat input, and pursuant to 401 KAR 51:001 Section 1(118)(c), fugitive emissions are included in determining the source's potential to emit (PTE).

## SECTION 2 – CURRENT APPLICATION AND EMISSION SUMMARY FORM

Permit Number: V-26-012

| Activity | Application Received | Application Complete |
|---|---|---|
| APE20250001 | 1/27/2025 | 3/28/2025 |
| APE20250002 | 2/27/2025 | 4/28/2025 |

Permit Action: ☐ Initial ☒ Renewal ☒ Significant Rev ☐ Minor Rev ☐ Administrative

Construction/Modification Requested? ☒Yes ☐No NSR Applicable? ☐Yes ☒No

Previous 502(b)(10) or Off-Permit Changes incorporated with this permit action ☒Yes ☐No

**Description of Action:**
EKPC – John Sherman Cooper Power Station submitted a significant revision request in January 2025 (APE20250001) and submitted a permit renewal application in February 2025 (APE20250002). Permit V-26-012 incorporates both the significant revision changes and the renewal request. Additionally, six off permit changes were submitted between the previous renewal in 2018 and the current permitting actions. All changes are listed below.
APE20200004 Off-permit change received 6/24/2020:

- Added EU 16 *Non-Emergency Leachate Transfer Pump Engine*; 12.8 HP LPG-fired Westinghouse WGEN9500DF engine.

APE20210002 Off-permit change received 1/7/2021:

- Request to reduce PM controls to perform routine PM CEMS Relative Correlation Audit (RCA) testing on Cooper Common Stack 1.

APE20230005 Off-permit change received 6/30/2023:

- Addition of auxiliary control solution (MerControl 7895) to respond to potential sudden increases in mercury concentration from coal.

APE20240001 Off-permit change received 1/12/2024:

- Request to reduce PM controls to perform routine PM CEMS Relative Correlation Audit (RCA) testing on Cooper Common Stack 1.

APE20250001 Significant Revision received 1/27/2025:

- CCGT PSD Project 1 – Construction of two dual-fuel combustion turbines (EUs 18 & 19) and associated support equipment:
    - EU 20 Natural Gas-Fired Auxiliary Boiler for CCGT
    - EUs 23 & 24 Natural Gas-Fired Dew Point Heaters for EUs 18 & 19
    - EUs 29A, 29B & 29C Natural Gas-Fired HVAC Heaters
    - EUs 21 & 22 Diesel-Fired Emergency Generator Engine and Fire Pump Engine
    - EUs 26A, 26B, 27, 28 Fuel Oil and Diesel fuel Storage Tanks
    - EU 25 CCGT 9-Cell Mechanical Draft Cooling Tower
    - EUs 30 & 31 15 Circuit Breakers with a total of 786 lb $SF_6$
    - EU 33 Natural Gas Piping Fugitives
    - EU 32 CCGT Haul roads
    - EU 34 Sulfuric Acid Tank
- C2 PSD Project 2 – Modification of Unit 02 (EU 02) to Co-Fire Natural Gas
    - Addition of EU 17 Natural Gas-Fired Dewpoint Heater
    - Removal of EU 03-01, 03-02, 03-04, 03-06, 03-07, 03-08, 07-01, 07-02, 07-03

  - Addition of EU 35 – Coal Storage and Handling Operations for Coal Stockpile #2
- Removal of EU 09, Emission Point 09-08, Lime Dust Silo.
- Modification of EU 10 Haul Roads to account for traffic changes
- Due to the projects' exceedance of the significant emission rate (SER) for PM, $PM_{10}$, $PM_{2.5}$, CO, VOC, $H_2SO_4$, and GHG, the project is considered a major modification to an existing major stationary source and is subject to New Source Review. Analyses of the projects are provided after the V-26-012 Emission Summary table below.

APE20250002 Renewal application received 2/27/2025:

- Application for Title V operating and Acid Rain permit renewal received more than six months prior to expiration of current Title V operating permit, V-18-027.
- Remove wood waste as a secondary fuel for EU 01.
- The Division removed CAM as an applicable requirement for EU 05 and EU 09-04. See Section 3 for information regarding the specific emission unit and Section 5 for CAM applicability tests for all emission units at the facility.

| **V-26-012 Emission Summary** | | | | |
|---|---|---|---|---|
| **Pollutant** | **2024 Actual (tpy)** | **Previous PTE V-18-027 (tpy)** | **Change (tpy)** | **Revised PTE V-26-012 (tpy)** |
| CO | 63.22 | 458.81 | 6587.11 | 7045.92 |
| $NO_X$ | 333.06 | 3620.46 | -121.57 | 3498.88 |
| PT | 150.65 | 1162.23 | -377.72 | 784.51 |
| $PM_{10}$ | 101.16 | 713.77 | -122.55 | 591.22 |
| $PM_{2.5}$ | 100.86 | 708.57 | -133.67 | 574.90 |
| $SO_2$ | 134.11 | 11037.08 | -10135.60 | 901.46 |
| VOC | 7.36 | 45.73 | 532.27 | 578.00 |
| Lead | 3.62E-03 | 1.32E-1 | -0.062 | 0.07 |
| **Greenhouse Gases (GHGs)** | | | | |
| Carbon Dioxide | 534,466.12 | 3,669,242 | 570733 | 4,239,975 |
| Methane | 4.20 | 23.84 | 134.38 | 158.22 |
| Nitrous Oxide | 3.14 | 17.62 | 4.38 | 22 |
| Sulfur Hexafluoride | 0.00 | 0.00 | 1.97E-4 | 1.97E-4 |
| $CO_2$ Equivalent ($CO_2e$)* | 535,418.18 | 3,674,578 | 575,703 | 4250281 |
| **Hazardous Air Pollutants (HAPs)** | | | | |
| Acetaldehyde | N/A | 1.30E-01 | 3.6 | 3.73 |
| Benzene | N/A | 2.75E-01 | 0.295 | 0.57 |
| Formaldehyde | 1.96E-04 | 1.28E-01 | 13.71 | 13.84 |
| Hexane; N-Hexane | N/A | 1.41E-02 | 19.16 | 19.17 |
| Hydrochloric Acid | 1.30 | 145.85 | -141.28 | 4.57 |
| Hydrofluoric Acid | 2.96E-01 | 33.71 | -32.88 | 0.83 |
| Hydrogen Bromide | N/A | N/A | 3.25 | 3.25 |
| Manganese, Total (as Mn) | 1.34E-02 | 7.48E-02 | 2.22 | 2.29 |
| Toluene | 2.07E-06 | 5.26E-02 | 1.88 | 1.93 |
| Xylenes (Total) | 7.20E-07 | 6.78E-03 | 0.91 | 0.92 |

| | | | | |
|---|---|---|---|---|
| Combined HAPs: | 1.61 | 181.74 | -130.21 | 51.53 |
| Non-Hazardous Air Pollutants | | | | |
| Ammonia | N/A | N/A | 979.36 | 979.36 |
| Sulfuric Acid Mist | N/A | N/A | 61.47 | 61.47 |

*All $CO_2e$ values were calculated using global warming potential values published in 40 CFR Part 98 as of March 2026.

**PSD Applicability Analysis:**
The application to construct and operate two dual fuel combustion turbines with associated support equipment and to modify emission unit 02 to co-fire natural gas consists of two PSD projects at the facility:

**Project 1 – CCGT:** Construction of two dual-fuel combustion turbines and associated support equipment. EUs 18, 19, 20, 23, 24, 29A, 29B, 29C, 21, 22, 26A, 26B, 27, 28, 25, 33, 30, 31, 32, and 34.

**Project 2 – C2:** Modification of EU 02 to co-fire natural gas, addition of EUs 17 and 35, and modification of EUs 03 and 10.

Kentucky has incorporated the requirements of the New Source Review (NSR) Prevention of Significant Deterioration (PSD) program into its State Implementation Plan under 401 KAR 51:017. Pursuant to 401 KAR 51:017, Section 1(1), PSD is applicable to these projects, as EKPC Cooper is an existing major stationary source located in Pulaski County, an area designated attainment or unclassifiable. Provisions of 401 KAR 51:017, Sections 8 through 16 apply to a major modification of an existing major stationary source which results in a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant.

# I. Project 1 Emissions:

## A. Project PSD Significance

The part of the application associated with constructing two dual-fuel combustion turbines and associated support equipment is one of two PSD projects at the facility. East Kentucky Power Cooperative calculated the potential air pollutants emitted by the project for the following regulated NSR pollutants: $NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$, and greenhouse gases (calculated as $CO_2$ equivalent, using the global warming potential values as published in 40 CFR Part 98 Table A-1 to Subpart A in March of 2026).

Potential to emit pollutants at this facility were calculated based on emission factors obtained from US EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, engineering estimates, and manufacturer's specifications. Based on these emission factors, and the assumption of 8,760 hours of operation per year (unless otherwise noted), the potential emissions of regulated NSR pollutants, $NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$, and GHGs exceed the thresholds as indicated in the table, Project 1 – CCGT PSD Significance below. A discussion of each pollutant, sources, calculation assumptions, emission factor sources, and the pollutant's PSD significance follows.

***Project 1 – CCGT PSD Significance***

| Pollutant | PEI (tpy) | Significant Emission Rate (increase in tpy) | PSD Significant Emissions Increase? |
|---|---|---|---|
| $NO_X$ | 359.3 | 40 | Yes |
| CO | 5,626.3 | 100 | Yes |
| VOC | 503.5 | 40 | Yes |
| $SO_2$ | 29.0 | 40 | No |
| PM | 175.2 | 25 | Yes |
| $PM_{10}$ | 171.3 | 15 | Yes |
| $PM_{2.5}$ | 170.7 | 10 | Yes |
| $H_2SO_4$ | 49.8 | 7 | Yes |
| Pb | 0.05 | 0.6 | No |
| GHGs ($CO_2e$) | 2,985,116 | 75,000 | Yes |

A significant emissions increase occurs when a modification causes an increase in emissions of a regulated NSR pollutant equal to or greater than the **significant emission rate (SER)** for that pollutant as specified in 401 KAR 51:001, Section 1(218)(a). EKPC Cooper performed a PSD analysis to determine the **project emissions increase (PEI)** using the actual-to-potential applicability test for Project 1 (CCGT). Since actual emissions are zero, potential to emit is equal to the PEI. Fugitive emissions are included, because EKPC Cooper is one of the 28-source categories listed under 401 KAR 51:001, Section 1(118)(c). There were no projects completed during the 5-year contemporaneous period, so the PEI is equal to the net emissions increases for all NSR pollutants.

**B. Nitrogen Oxides ($NO_X$) Emissions**

$NO_X$ emissions originate from the combustion of fossil fuels. At high temperatures during combustion, $NO_X$ is formed by thermal fixation of $N_2$ in the combustion air, oxidation of nitrogen contained in the fuel, and formation of "prompt" nitrogen due to the presence of partially oxidized organic species within the flame. For this project, combustion of natural gas and diesel will primarily form thermal $NO_X$.

$NO_X$ is formed in three primary ways in a combustion turbine. The methods are as follows: Thermal $NO_X$, Prompt $NO_X$, and Fuel $NO_X$. Thermal $NO_X$ is formed mainly through the Zeldovich mechanism, where the $N_2$ and $O_2$ molecules in the combustion air react to form nitrogen monoxide (NO). Most thermal $NO_X$ is formed at high temperature zones downstream from the fuel injectors. Prompt $NO_X$ is a form of thermal $NO_X$ and is formed near the flame front when intermediate combustion products (such as HCN, N, and NH) are oxidized to form $NO_X$. Fuel $NO_X$ is formed when excess air allows nitrogen in the fuel to break free and form oxides. Natural gas and fuel oil contain relatively little fuel-bound nitrogen and therefore fuel $NO_X$ is not a major contributor to $NO_X$ emissions.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

$NO_X$ emissions from the combustion turbines are controlled by selective catalytic reduction (SCR) system and are calculated utilizing controlled, EKPC-required vendor guarantees for each fuel utilized in conjunction with vendor emissions data for uncontrolled emissions during startup (SU) and shutdown (SD). The EKPC-required vendor guarantee for natural gas combustion is 2.0 ppmvd at 15% $O_2$ during controlled, steady-state operations. This becomes a maximum controlled emission rate of 19.82 lb/hr. The EKPC-required vendor guarantee for fuel oil combustion is 4.5 ppmvd at 15% $O_2$ during steady-state operations, which becomes a maximum emission rate of 45.10 lb/hr. SU and SD emissions are calculated using a conservative number of hot, warm and cold startups and subsequent shutdowns. Siemens vendor data provides data for SU and SD emissions as shown:

| Event Type | Events per year | $NO_X$ Emission Factor (lb/event) | $NO_X$ (tpy) |
|---|---|---|---|
| N.G. Cold Startup | 15 | 321 | 2.41 |
| N.G. Warm Startup | 365 | 175 | 31.94 |
| N.G. Hot Startup | 585 | 110 | 32.18 |
| N.G. Shutdown | 965 | 56 | 27.02 |
| F.O. Cold Startup | 15 | 685 | 5.14 |
| F.O. Warm Startup | 15 | 436 | 3.27 |
| F.O. Hot Startup | 30 | 241 | 3.62 |
| F.O. Shutdown | 60 | 101 | 3.03 |
| | | **Total:** | **108.61** |

The worst-case PTE includes SU/SD emissions because SU/SD emissions are uncontrolled for $NO_X$. Steady-state operations are limited to 4,189 hours per year for natural gas and 852.6 hours per year for fuel oil when subtracting out a conservative amount of time for startups and shutdowns, as this is time needed for the SCR to reach its design capacity. Steady-state emissions of $NO_X$ for each fuel are listed in the table below.

| Fuel Type | Steady-state $NO_X$ PTE (tpy) |
|---|---|
| Natural Gas | 41.51 |
| Fuel Oil | 19.23 |
| **Total:** | **60.74** |

The contribution to the PEI for $NO_X$ from each combustion turbine is **169.3 tpy**.

**EU 20 – Natural Gas-Fired Auxiliary Boiler (99 MMBtu/hr)**
$NO_X$ emissions from the boiler are generated from burning natural gas at 99 MMBtu/hr. $NO_X$ control for this boiler consists of ultra-low $NO_X$ burners (ultra LNBs) and good combustion and operations practices. $NO_X$ emissions are converted from the EKPC-required vendor guarantee of 9 ppmv $NO_X$ at 3% $O_2$ utilizing the ideal gas law and the dry F factor for natural gas from Table 19-2 in Appendix A-7 to 40 CFR part 60, and the site-specific natural gas heat content of 1,060 Btu/scf. $NO_X$ PTE is calculated to be **5.0 tpy**.

**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
$NO_X$ emissions from the natural gas preheaters are generated from burning natural gas at 9.13 MMBtu/hr each. $NO_X$ control for these boilers consists of low $NO_X$ burners (LNBs) and good combustion and operations practices. $NO_X$ emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Controlled - Low $NO_X$ Burners" for small boilers less than 100 MMBtu/hr. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf.

Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. $NO_X$ PTE is calculated to be **2.0 tpy**, each, for EUs 23 and 24.

**EUs 29A, 29B, & 29C – Natural Gas-Fired HVAC Heaters**
$NO_X$ emissions from the HVAC heaters 29A, 29B, and 29C are generated from burning natural gas at 11.7, 0.24, and 1.08 MMBtu/hr, respectively. $NO_X$ control consists of good combustion and operations practices. $NO_X$ emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Uncontrolled" $NO_X$ emission factor. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf, so they were converted to utilize the site-specific heat content for consistency with the design rate. $NO_X$ PTE is **5.0 tpy** for EU 29A, **0.1 tpy** for EU 29B, and **0.5 tpy** for EU 29C.

**EU 21 – Diesel-Fired Emergency Generator Engine (12.5 MMBtu/hr)**
$NO_X$ emissions from the generator are generated from burning diesel fuel (fuel oil) at 0.113 Mgal/hr. $NO_X$ control for this generator consists of good combustion and operations practices. $NO_X$ emissions are calculated using the manufacturer supplied data for the Tier 2 certified engine and the 40 CFR 60, Subpart IIII emission standard for NOX + NMHC. NOX emissions calculations are based on the 40 CFR 60, Subpart IIII emission standard for NOx + NMHC multiplied by the ratio of emissions from AP-42 of NOx divided by (NOx + TOC). The calculations assume 500 hours of annual operation for a PTE of **5.6 tpy**. For the purposes of these calculations, VOC, NMHC, and TOC are used interchangeably.

**EU 22 – Diesel-Fired Fire Pump Engine**
$NO_X$ emissions from the fire pump engine are generated from burning diesel fuel (fuel oil) at 0.016 Mgal/hr. $NO_X$ control for this engine consists of good combustion and operations practices. $NO_X$ emissions are calculated using the manufacturer supplied data for the 40 CFR 60 Subpart IIII compliant engine and the 40 CFR 60, Subpart IIII emission standard for NOX + NMHC. NOX emissions calculations are based on the 40 CFR 60, Subpart IIII emission standard for NOx + NMHC multiplied by the ratio of emissions from AP-42 of NOx divided by (NOx + TOC). The calculations assume 500 hours of annual operation for a PTE of **0.5 tpy**. For the purposes of these calculations, VOC, NMHC, and TOC are used interchangeably.

**<u>$NO_X$ PSD Significance</u>**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI of $NO_X$ for Project 1 is 438 tons per year. This emission rate exceeds the SER for $NO_x$ of 40 tons per year. Thus, a BACT analysis for $NO_X$ is required for each piece of equipment that emits $NO_X$. Establishment of a BACT limit for the emission of $NO_X$ for each emission point that emits $NO_X$ is also required. Refer to the BACT Analysis for $NO_X$, below, for a discussion of the BACT for $NO_X$.

| Emission Unit | $NO_x$ (tpy) |
|---|---|
| 18 | 169.3 |
| 19 | 169.3 |
| 20 | 5.0 |
| 23 | 2.0 |
| 24 | 2.0 |

| | |
|---|---|
| 29A | 5.0 |
| 29B | 0.1 |
| 29C | 0.5 |
| 21 | 5.6 |
| 22 | 0.5 |
| **Total:** | **359.3** |

## C. Carbon Monoxide (CO) Emissions

CO is formed from the incomplete combustion of fuels. The unburned carbon in the fuel is oxidized to form CO instead of $CO_2$. Temperature and residence time in the combustion zone are key factors for CO emissions.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

CO is formed in a combustion turbine under operating conditions that result in incomplete combustion, such as insufficient oxygen, poor fuel air mixing, low combustion temperature, low combustion gas residence time, and load reduction.

CO emissions are controlled using an oxidation catalyst and are calculated utilizing controlled, EKPC-required vendor guarantees for each fuel utilized. The EKPC-required vendor guarantee for natural gas and fuel oil combustion is 2.0 ppmvd at 15% $O_2$ during steady-state operations. This becomes a maximum emission rate of 12.07 lb/hr for natural gas and 12.20 lb/hr for fuel oil. Siemens vendor data provides data for startup (SU) and shutdown (SD) emissions.

| Event Type | Events per year | CO Emission Factor (lb/event) | CO (tpy) |
|---|---|---|---|
| N.G. Cold Startup | 15 | 10,799 | 80.99 |
| N.G. Warm Startup | 365 | 5,328 | 972.36 |
| N.G. Hot Startup | 585 | 2,896 | 847.08 |
| N.G. Shutdown | 965 | 1,011 | 487.81 |
| F.O. Cold Startup | 15 | 21,348 | 160.11 |
| F.O. Warm Startup | 15 | 12,393 | 92.95 |
| F.O. Hot Startup | 30 | 6,423 | 96.35 |
| F.O. Shutdown | 60 | 1,229 | 36.87 |
| | | **Total:** | **2774.52** |

The worst-case PTE includes SU/SD emissions because SU/SD emissions are uncontrolled for CO. Steady-state operations are limited to 4,189 hours per year for natural gas and 852.6 hours per year for fuel oil when subtracting out a conservative amount of time for startups and shutdowns, as this is time needed for the oxidation catalyst to reach its design capacity. Steady-state emissions of CO for each fuel are listed in the table below.

| Fuel Type | Steady-state CO PTE (tpy) |
|---|---|
| Natural Gas | 25.28 |
| Fuel Oil | 5.20 |
| **Total:** | 30.48 |

The contribution to the PEI for CO from each combustion turbine is **2,805 tpy**.

**EU 20 – Natural Gas-Fired Auxiliary Boiler (99 MMBtu/hr)**
CO emissions from the boiler are generated from burning natural gas at 99 MMBtu/hr. CO control for this boiler consists of an oxidation catalyst and good combustion and operations practices. CO emissions are calculated using the EKPC-required vendor guarantee of 4 ppmv CO at 3% $O_2$, converted using ideal gas law, the natural gas F-factor from Method 19 in Appendix A-7 of 40 CFR part 60, and the site-specific natural gas heat content of 1,060 Btu/scf. CO PTE for EU 20 is **1.4 tpy**.

**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
CO emissions from the natural gas preheaters are generated from burning natural gas at 9.13 MMBtu/hr each. CO control for these boilers consists of good combustion operating and maintenance practices. CO emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Controlled-Low $NO_X$ Burners." AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. CO PTE is **3.3 tpy**, each for EUs 23 and 24.

**EU 29A, 29B, & 29C – Natural Gas-Fired HVAC Heaters**
CO emissions from the HVAC heaters EUs 29A, 29B, and 29C are generated from burning natural gas at 11.7, 0.24, and 1.08 MMBtu/hr, respectively. CO control consists of good combustion and operations practices. CO emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Uncontrolled" CO emission factor. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. CO PTE is **4.2 tpy** for EU 29A, **0.1 tpy** for EU 29B, and **0.4 tpy** for EU 29C.

**EU 21 – Diesel-Fired Emergency Generator Engine (12.5 MMBtu/hr)**
CO emissions from the generator are generated from burning diesel fuel (fuel oil) at 0.113 Mgal/hr. CO control for this generator consists of good combustion and operations practices. CO emissions are calculated using the certified engine manufacturer's guaranteed Tier 2 NSPS emission limitation of 3.5 g/kW-hr. The calculations assume 500 hours of annual operation for the purpose of calculating PTE, which is **3.2 tpy**.

**EU 22 – Diesel-Fired Fire Pump Engine**
CO emissions from the fire pump engine are generated from burning diesel fuel (fuel oil) at 0.016 Mgal/hr. CO control for this engine consists of good combustion and operations practices. CO emissions are calculated using the certified engine manufacturer's data for the 40 CFR 60, Subpart IIII compliant engine. The calculations assume 500 hours of annual operation for the purposes of calculating a CO PTE of **0.4 tpy**.

**<u>CO PSD Significance</u>**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 1 is 5,626.3 tons per year of CO, exceeding the SER level for CO of 100 tons per year. Thus, a BACT analysis for CO is required for each piece of equipment that emits CO. Establishment of a BACT limit for the emission of CO for each emission point that emits CO is also required. Refer to the BACT Analysis for CO, below, for a discussion of the BACT for CO.

| Emission Unit | CO (tpy) |
|---|---|
| 18 | 2,805.0 |
| 19 | 2,805.0 |
| 20 | 1.4 |
| 23 | 3.3 |
| 24 | 3.3 |
| 29A | 4.2 |
| 29B | 0.1 |
| 29C | 0.4 |
| 21 | 3.2 |
| 22 | 0.4 |
| **Total:** | **5,626.3** |

**D. <u>Volatile Organic Compounds (VOC) Emissions</u>**

VOC emissions are formed from the incomplete combustion of fossil fuels and the storage and transmission of fuels. Temperature and residence time are key factors for VOC formation.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

VOCs are emitted from the combustion turbines as a result of incomplete combustion. VOCs are controlled by an oxidation catalyst, resulting in an estimated 30% destruction efficiency. During startup and shutdown, it is assumed that VOC emissions are uncontrolled due to required flue gas temperature for proper catalyst functionality.

VOC emissions are calculated utilizing controlled, EKPC-required vendor guarantees for each fuel utilized. The EKPC-required vendor guarantee for natural gas combustion is 1.0 ppmvd at 15% $O_2$ during steady-state operations. This becomes a maximum emission rate of 3.46 lb/hr. The EKPC-required vendor guarantee for fuel oil combustion is 2.0 ppmvd at 15% $O_2$ during steady-state operations, resulting in a maximum emission rate of 6.99 lb/hr. Siemens vendor data provides data for startup (SU) and shutdown (SD) emissions.

| Event Type | Events per year | VOC Emission Factor (lb/event) | VOC (tpy) |
|---|---|---|---|
| N.G. Cold Startup | 15 | 928 | 6.96 |
| N.G. Warm Startup | 365 | 462 | 84.32 |
| N.G. Hot Startup | 585 | 253 | 74.00 |
| N.G. Shutdown | 965 | 64 | 30.88 |
| F.O. Cold Startup | 15 | 2,431 | 18.23 |
| F.O. Warm Startup | 15 | 1,406 | 10.55 |
| F.O. Hot Startup | 30 | 722 | 10.83 |
| F.O. Shutdown | 60 | 136 | 4.08 |
| | | **Total:** | **239.9** |

The worst-case PTE includes SU/SD emissions because SU/SD emissions are uncontrolled for VOC. Steady-state operations are limited to 4,189 hours per year for natural gas and 852.6 hours per year for fuel oil when subtracting out a conservative amount of time for startups and shutdowns, as this is time needed for the oxidation catalyst to reach its design capacity. Steady-state emissions of VOC for each fuel are listed in the table below.

| Fuel Type | Steady-state VOC PTE (tpy) |
|---|---|
| Natural Gas | 7.2 |
| Fuel Oil | 3.0 |
| **Total:** | **10.2** |

The contribution to the PEI for CO from each combustion turbine is **250.1 tpy**.

**EU 20 – Natural Gas-Fired Auxiliary Boiler (99 MMBtu/hr)**
VOC emissions from the boiler are generated from burning natural gas at 99 MMBtu/hr. VOC control for this boiler consists of an oxidation catalyst and good combustion and operations practices. VOC emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors from AP-42 were converted using this ratio for consistency with the design rate. VOC PTE is calculated to be **2.3 tpy**.

**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
VOC emissions from the natural gas preheaters are generated from burning natural gas at 9.13 MMBtu/hr each. VOC control for these boilers consists of good combustion and operations practices. VOC emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. VOC PTE is calculated to be **0.2 tpy**, each.

**EU 29A, 29B, & 29C – Natural Gas-Fired HVAC Heaters**
VOC emissions from the HVAC heaters EUs 29A, 29B, and 29C are generated from burning natural gas at 11.7, 0.24, and 1.08 MMBtu/hr, respectively. VOC control consists of good combustion and operations practices, and emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. VOC PTE is calculated to be **0.3 tpy** for EU 29A, **0.01 tpy** for EU 29B, and **0.02 tpy** for EU 29C.

**EU 21 – Diesel-Fired Emergency Generator Engine (12.5 MMBtu/hr)**
VOC emissions from the generator are generated from burning diesel fuel (fuel oil) at 0.113 Mgal/hr. VOC control for this generator consists of good combustion and operations practices. VOC emissions are calculated using the manufacturer supplied data for the Tier 2 certified engine and the 40 CFR 60, Subpart IIII emission standard for NOX + NMHC. VOC emissions calculations are based on the 40 CFR 60, Subpart IIII emission standard for NOx + NMHC multiplied by the ratio of emissions from AP-42 of TOC divided by (NOx + TOC). The calculations assume 500 hours of annual operation for a VOC PTE of **0.2 tpy**. For the purposes of these calculations, VOC, NMHC, and TOC are used interchangeably.

**EU 22 – Diesel-Fired Fire Pump Engine**
VOC emissions from the fire pump engine are generated from burning diesel fuel (fuel oil) at 0.016 Mgal/hr. VOC control for this engine consists of good combustion and operations practices. VOC emissions are calculated using the manufacturer supplied data for the 40 CFR 60 Subpart IIII compliant engine and the 40 CFR 60, Subpart IIII emission standard for NOX + NMHC. VOC emissions calculations are based on the 40 CFR 60, Subpart IIII emission standard for NOx + NMHC multiplied by the ratio of emissions from AP-42 of TOC divided by (NOx + TOC). The calculations assume 500 hours of annual operation for the purpose of calculating PTE. VOC PTE is calculated to be **0.04 tpy**. For the purposes of these calculations, VOC, NMHC, and TOC are used interchangeably.

**EUs 26A, 26B, 27 & 28 – External Fuel Oil Storage Tanks**
VOC emissions from the fuel oil storage tanks are generated through normal operation and are classified as Breathing Loss or Working Loss. Breathing losses occur over time as the fuel stored in the tank slowly evaporates. Working losses occur as fuel is being filled and/or dispensed. Both types of emissions are VOC emissions. Breathing loss emissions are calculated based on the gallon-year storage capacity of the tank, while working loss emission calculations are based on the throughput of fuel in gallons. VOC emissions are calculated with parameters provided by EKPC using the EPA methodology presented in AP-42 through the software TankESP. VOC PTE from both breathing and working losses is calculated to be 0.41 tpy for EU 26A, 0.41 for EU 26B, 0.00051 tpy for EU 27, and 0.000122 tpy for EU 28.

**EU 33 – Natural Gas Piping Component Fugitive Emissions**
VOC emissions from natural gas piping components occur through leaks from connections between pipes, valves, pumps, and other connections. VOC emissions are calculated using site-specific component types and numbers provided by EKPC, site-specific VOC content weight percentages of natural gas, and EPA-453/R-95/017 Protocol for Equipment Leak Emission Estimates, Page 2-15. VOC PTE is calculated to be 0.42 tpy.

**VOC PSD Significance**
The emission calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 1 is 518.01 tons per year of VOC, exceeding the SER of 40 tons per year. Thus, a BACT analysis for VOC is required for each piece of equipment that emits VOC. Establishment of a BACT limit for the emission of VOC for each emission point that emits VOC is also required. Refer to the BACT Analysis for VOC, below, for a discussion of the BACT for VOC.

| Emission Unit | VOC (tpy) |
|---|---|
| 18 | 250.1 |
| 19 | 250.1 |
| 20 | 2.3 |
| 23 | 0.2 |
| 24 | 0.2 |
| 29A | 0.3 |
| 29B | 0.01 |
| 29C | 0.02 |

| | |
|---|---|
| 21 | 0.2 |
| 22 | 0.04 |
| **Total:** | **503.5** |

## E. Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions

PM, $PM_{10}$, and $PM_{2.5}$ are regulated NSR pollutants. $PM_{10}$ has an aerodynamic diameter of 10 microns or less, and $PM_{2.5}$ has an aerodynamic diameter of 2.5 microns or less. Both filterable and condensable components are required to be included in applicability determinations and in establishing emissions limitations for $PM_{10}$ and $PM_{2.5}$. Filterable PM is defined as particles directly emitted as a solid or liquid at stack conditions and captured on the filter of a stack test train. Condensable PM is material that is in a vapor phase at stack conditions that condenses to form a solid or liquid immediately after discharge from a stack.

Particulates, often discharged through stacks or vents, may also be emitted in a fugitive form. Under 401 KAR 51:001, fugitive emissions are defined as those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Fugitive emissions are counted toward emissions totals, as EKPC Cooper Station is a listed 28-source category. When speciation of particulate type is unavailable, all particulate is assumed to be part of the same size fraction for conservative purposes when calculating the Potential to Emit.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

$PM/PM_{10}/PM_{2.5}$ is formed in a combustion turbine as a result of incomplete combustion and from ash and sulfur in the fuel. Natural gas and fuel oil generate low PM emissions in comparison to other fuels due to the low ash and sulfur content. Filterable PM includes airborne PM, which passes through the inlet air filters, solids in the fuel supply, and metallic rust or oxidization products. The SCR system also produces $PM/PM_{10}/PM_{2.5}$ emissions including ammonium bisulfate, ammonium sulfate, and secondary PM formation due to ammonia slip.

$PM/PM_{10}/PM_{2.5}$ emissions are calculated using EKPC-required vendor estimates for each fuel utilized. All PM emissions are assumed to be less than 2.5μm in average diameter (i.e. $PM = PM_{10} = PM_{2.5}$). Since EKPC uses an oxidation catalyst system, it is possible to form condensable PM (CPM) and sub-micron sized filterable PM during certain conditions. One possible scenario is sulfate formation from $H_2SO_4$, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. Another possibility is nitrate forming in the form of $NH_4NO_3$.

The EKPC-required vendor data for natural gas combustion is a maximum of 0.5 grains of sulfur (S) per 100scf (0.5gr/100scf) with 85% conversion to $(NH_4)_2SO_4$ during steady-state operations at the worst-case PTE scenario provided by the vendor. This becomes a maximum emission rate of 16.76 lb/hr, or 64.4 tpy at 8,760 hours minus 1,080 hours of fuel oil use. The EKPC-required vendor data for fuel oil combustion is a maximum of 15 ppm sulfur (S) with 85% conversion to $(NH_4)_2SO_4$ during steady-state operations at the worst-case PTE scenario provided by the vendor. This becomes a maximum emission rate of 36.90 lb/hr, or 19.9 tpy at the maximum 1,080 hours per year of fuel oil use. Each CT contributes a total of **84.3 tpy** to the PEI.

**EU 20 – Natural Gas-Fired Auxiliary Boiler (99 MMBtu/hr)**
**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
**EU 29A, 29B, & 29C – Natural Gas-Fired HVAC Heaters**
$PM/PM_{10}/PM_{2.5}$ emissions from the boiler are generated from burning natural gas. $PM/PM_{10}/PM_{2.5}$ emissions typically consist of larger molecular weight hydrocarbons that are not fully combusted upon exiting the boiler. Maintenance issues and poor air/fuel mixing contribute to filterable PM emissions from natural gas combustion. $PM/PM_{10}/PM_{2.5}$ control for this boiler consists of good combustion and operations practices and burning pipeline quality natural gas. $PM/PM_{10}/PM_{2.5}$ emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2 and the EPA Speciate Database. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. $PM/PM_{10}/PM_{2.5}$. The PTE from these units is in the PM PSD Significance table below.

**EU 21 – Diesel-Fired Emergency Generator Engine (12.5 MMBtu/hr)**
**EU 22 – Diesel-Fired Fire Pump Engine**
$PM/PM_{10}/PM_{2.5}$ emissions from the generator are generated from burning diesel fuel (fuel oil) at 0.113 Mgal/hr. $PM/PM_{10}/PM_{2.5}$ control for this generator consists of good combustion and operations practices for filterable PM and burning ultra-low sulfur diesel fuel (ULSFO) for condensable PM. $PM/PM_{10}/PM_{2.5}$ emissions are calculated using the manufacturer supplied data for the certified engine and the 40 CFR 60, Subpart IIII emission standard for PM. The calculations assume 500 hours of annual operation for the purposes of calculating PTE, which is 0.18 tpy for EU 21 and 0.02 tpy for EU 22.

**EU 25 – CCGT Cooling Tower (Mechanical Draft Cooling Tower, 9 Cells)**
$PM/PM_{10}/PM_{2.5}$ emissions from the cooling tower are generated from the particulates encapsulated in the water droplets. The water circulating in the tower contains small amounts of dissolved solids (such as calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower. $PM/PM_{10}/PM_{2.5}$ control for the cooling tower consists of utilizing drift eliminators for the mechanical cooling process. $PM/PM_{10}/PM_{2.5}$ emissions are calculated using the procedure outlined in EPA's AP-42 Section 13.4 which requires total dissolved solids in the water, gallons of recirculating water per hour and the drift percentage for the mist eliminators. Potential emissions of PM, $PM_{10}$, and $PM_{2.5}$ are 4.54, 0.59, and 0.01 tpy, respectively.

**EU 32 – CCGT Haul Roads**
PM, $PM_{10}$, and $PM_{2.5}$ emissions from haul roads are generated from vehicle transport of aqueous ammonia, ULSFO, water treatment chemicals, and cooling tower chemicals around the EKPC Cooper site. Loose material on the road surface becomes airborne during vehicle travel and is considered fugitive PM emissions. PM, $PM_{10}$, and $PM_{2.5}$ control for the haul roads consists of paving the roadways, sweeping the roadways, wet suppression, and good housekeeping practices to minimize fugitive dust emissions. PM, $PM_{10}$, and $PM_{2.5}$ emissions are calculated using mean vehicle weights, a silt loading of 0.6 $g/m^2$, and vehicle miles traveled provided by EKPC. The calculation is outlined in EPA's AP-42 Section 13.2.1. Precipitation is not accounted for in estimating potential emissions from the additional haul roads at the facility.

**PM/$PM_{10}$/$PM_{2.5}$ PSD Significance**

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 1 is 188.93/184.36/184.49 tons per year of PM/$PM_{10}$/$PM_{2.5}$, respectively. These emission rates exceed the SER level for PM/$PM_{10}$/$PM_{2.5}$ of 25/15/10 tons per year, respectively. Thus, a BACT analysis for PM/$PM_{10}$/$PM_{2.5}$ is required for each piece of equipment that emits PM/$PM_{10}$/$PM_{2.5}$. Establishment of a BACT limit for the emission for each emission point that emits PM/$PM_{10}$/$PM_{2.5}$ is also required. Refer to the BACT Analysis for PM/$PM_{10}$/$PM_{2.5}$ in Section 2.III.D. of this document for a BACT discussion.

| ***PM PSD Significance*** | | | |
|---|---|---|---|
| **Emission Unit** | **PM PEI (tpy)** | **$PM_{10}$ PEI (tpy)** | **$PM_{2.5}$ PEI (tpy)** |
| 18 | 84.28 | 84.28 | 84.28 |
| 19 | 84.28 | 84.28 | 84.28 |
| 20 | 1.42 | 1.42 | 1.42 |
| 21 | 0.18 | 0.18 | 0.18 |
| 22 | 0.03 | 0.03 | 0.03 |
| 23 | 0.14 | 0.14 | 0.14 |
| 24 | 0.14 | 0.14 | 0.14 |
| 25 | 4.54 | 0.59 | 0.01 |
| 29A | 0.17 | 0.17 | 0.17 |
| 29B | 0.0036 | 0.0036 | 0.0036 |
| 29C | 0.016 | 0.016 | 0.016 |
| 32 | 0.015 | 0.0030 | 0.00074 |
| **Total** | **175.2** | **171.3** | **170.7** |

**F. Sulfuric Acid ($H_2SO_4$) Emissions**

Sulfuric Acid Mist (SAM or $H_2SO_4$) emissions are formed when sulfur-containing compounds are oxidized to sulfur trioxide ($SO_3$), which then combines with water vapor to form fine droplets or aerosols of sulfuric acid. This conversion is influenced by the sulfur content in the fuel, ambient temperature, relative humidity, evaporative cooling operations, duct burner operations, oxidation over an oxidation catalyst, oxidation within the SCR, available moisture, ammonia slip concentration and acid dew point. Any high-temperature combustion source that burns fossil fuel is a source of SAM. Additionally, SAM is emitted through the storage and transmission of sulfuric acid.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

Since fuel oil has a higher sulfur content, emissions of $H_2SO_4$ are calculated using the maximum amount of hours allowed by the permit to combust fuel oil at steady-state with the remainder of the year's hours combusting natural gas at steady-state. Startup and shutdown emissions of $H_2SO_4$ are lower than during steady-state operations due to the oxidation in the SCR and are not considered for PTE calculations.

Emissions for natural gas combustion are calculated utilizing a federally enforceable maximum of 0.5 grains of sulfur (S) per 100scf (0.5gr/100scf) and assuming a 100% conversion of all sulfur to $H_2SO_4$. The maximum natural gas heat input capacity of 2,734 MMBtu/hr is used to calculate emissions at 7,680 hours per year, which is 8,760 hours per year minus 1,080 hours per year allowed for fuel oil usage. The PEI from natural gas combustion is 21.62 tpy $H_2SO_4$.

The maximum federally enforceable fuel oil sulfur content of 15 ppm is utilized in calculating potential $H_2SO_4$ emissions, assuming 100% conversion of sulfur to $H_2SO_4$. At 1,080 hours per year, a maximum fuel oil heat input capacity of 2,597 MMBtu/hr, and a site-specific fuel oil higher heating value of 136,200 Btu/scf, the potential $H_2SO_4$ emissions are 3.26 tpy.

**EU 20 – Natural Gas-Fired Auxiliary Boiler (99 MMBtu/hr)**
**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
**EUs 29A & B/C – Natural Gas-Fired HVAC Heaters**
$H_2SO_4$ emissions from the boilers are generated from combusting natural gas. $H_2SO_4$ control for this boiler consists of burning pipeline quality natural gas with a maximum sulfur content of 0.5 gr/100scf along with good combustion and operations practices. Potential emission calculations assume 100% of the sulfur is converted to $SO_2$, of which 5% is converted to $SO_3$ then $H_2SO_4$, resulting in a PTE of 0.04 tpy for EU 20, 0.004 tpy each for EUs 23 and 24, 0.005 tpy for EU 29A, 0.0001 tpy for EU 29B, and 0.0005 tpy for EU 29C.

**EU 34 – 93% Sulfuric Acid Tank**
$H_2SO_4$ emissions from the sulfuric acid storage tank are generated through normal operation and are classified as Breathing Loss or Working Loss. Breathing losses occur over time as the liquid stored in the tank slowly evaporates. Working losses occur as sulfuric acid is being filled and/or dispensed. Breathing loss emissions are calculated based on the gallon-year storage capacity of the tank, while working loss emission calculations are based on the throughput of the liquid in gallons. Working loss emissions are controlled using a submerged fill pipe. $H_2SO_4$ emissions are calculated with parameters provided by EKPC using the EPA methodology presented in AP-42 Section 7.1 through the software TankESP. $H_2SO_4$ PTE from both breathing and working losses is calculated to be 1.46E-07 tpy.

**$H_2SO_4$ PSD Significance**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 1 is 49.8 tpy of $H_2SO_4$, exceeding the SER level of 7 tpy. Thus, a BACT analysis is required for each piece of equipment that emits $H_2SO_4$. Establishment of a BACT limit for the emission of $H_2SO_4$ for each emission point that emits $H_2SO_4$ is also required. Refer to the BACT Analysis for $H_2SO_4$, under Section 2.III.E. of this document for a discussion of the BACT for VOC.

| Emission Unit | $H_2SO_4$ (tpy) |
|---|---|
| 18 | 24.88 |
| 19 | 24.88 |
| 20 | 0.04 |
| 23 | 0.004 |
| 24 | 0.004 |
| 29A | 0.005 |
| 29B | 0.0001 |
| 29C | 0.0005 |

 

| | |
|---|---|
| 34 | 0.00000015 |
| **Total:** | **49.8** |

## G. Greenhouse Gas (GHG) Emissions

GHG emissions originate from the complete combustion of fossil fuels, fugitive leaks from natural gas piping, and leakage from circuit breakers. $CO_2$ production from complete combustion occurs by a complete reaction between carbon and oxygen in the air and proceeds stoichiometrically. Calculations utilize global warming potentials of 28 for methane, 265 for nitrous oxide, and 23,500 for sulfur hexafluoride, as codified in Appendix A-1 of 40 CFR part 98 effective January 1, 2025.

**EUs 18 & 19 – Dual Fuel Combustion Turbines Units 3 & 4**

The vast majority of GHGs emitted from combustion turbines, on a $CO_2$ equivalent ($CO_2e$) basis, are $CO_2$. $CH_4$ emissions from turbines are typically extremely low. $CH_4$ is formed when fossil fuels are not burned completely in combustion. Very small amounts of $N_2O$ are formed during complete gas combustion because most oxides of nitrogen will oxidize completely to form $NO_2$, which is not a GHG. GHG control for the combustion turbines consists of good combustion and operations practices.

GHG emission factors from 40 CFR Part 98, Subpart C, Tables C-1 & C-2 utilize a natural gas heat content of 1,026 Btu/scf and a diesel heat content of 138 MMBtu/Mgal from 40 CFR 98. The design rate utilizes the site-specific heat content of 1,060 Btu/scf or 136.2 MMBtu/Mgal depending on the fuel used. Emission factors were converted to utilize the corresponding site-specific heat content for consistency with the design rate. Expected worst case scenario $CO_2$, Methane ($CH_4$), Nitrous Oxide, and GHG emissions for each turbine are listed in the table below.

| Fuel Type | $CO_2$ (tpy) | Methane ($CH_4$) (tpy) | Nitrous Oxide (tpy) | GHG (tpy) |
|---|---|---|---|---|
| Natural Gas | 1,228,091 | 23.14 | 2.31 | 1,229,351 |
| Fuel Oil | 228,663 | 9.28 | 1.86 | 229,416 |
| **Total** | 1,456,754 | 32.42 | 4.17 | **1,458,767** |

**EU 20 – Natural Gas-Fired Auxiliary Boiler**
**EUs 23 & 24– Natural Gas-Fired Dewpoint Heaters**
**EU 29A, 29B, & 29C – Natural Gas-Fired HVAC Heaters**

GHG emissions from these units are generated from combusting natural gas. GHG control for this boiler consists of good combustion and operations practices and burning pipeline quality natural gas. GHG emission factors from 40 CFR Part 98, Subpart C, Tables C-1 & C-2 utilize a natural gas heat content of 1,026 Btu/scf. The design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. $CO_2$, Methane ($CH_4$), and Nitrous Oxide emissions, along with GHG total PTE are as follows:

| Emission Unit | $CO_2$ (tpy) | Methane ($CH_4$) (tpy) | Nitrous Oxide (tpy) | GHG (tpy) |
|---|---|---|---|---|
| 20 | 50,724 | 0.96 | 0.10 | **50,776** |
| 23 | 4,677 | 0.088 | 8.81E-03 | **4,682** |
| 24 | 4,677 | 0.088 | 8.81E-03 | **4,682** |

| | | | | |
|---|---|---|---|---|
| 29A | 5,994 | 0.112 | 0.011 | **6,000** |
| 29B | 122 | 2.31E-03 | 2.31E-04 | **123** |
| 29C | 553 | 0.010 | 1.04E-03 | **554** |

**EU 21 – Diesel-Fired Emergency Generator Engine**
**EU 22 – Diesel-Fired Fire Pump Engine**
GHG emissions from the engines are generated from burning diesel fuel (fuel oil). GHG control consists of purchasing an EPA-certified engine, burning ultra-low sulfur diesel fuel (ULSFO), and good combustion and operations practices. GHG emission factors from 40 CFR Part 98, Subpart C, Tables C-1 & C-2 utilize a diesel heat content of 138 MMBtu/Mgal. The design rate utilizes the site-specific heat content of 136.2 MMBtu/Mgal. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. The calculations assume 500 hours of annual operation for the purposes of calculating PTE. For EU 21, $CO_2$, Methane ($CH_4$), and Nitrous Oxide emissions are calculated to be 627 tpy, 0.025 tpy, and 0.005 tpy, respectively, with a GHG PTE of 629 tpy. EU 22 are calculated as 88.45 tpy, 0.0036 tpy, and 0.0007 tpy, respectively, with a GHG PTE of **89 tpy**.

**EUs 30 & 31 – Circuit Breakers**
GHG emissions from the circuit breakers are generated from leaks due to normal usage of the equipment. While the electrical equipment containing $SF_6$ (sulfur hexafluoride) is designed not to leak, occasional leaks of $SF_6$ to the atmosphere are responsible for the GHG emissions. GHG control for the circuit breakers consists of purchasing a low leak circuit breaker system, using a leak detection system, and recordkeeping associated with the leak detection system. GHG emissions are calculated using the $SF_6$ leak rate BACT limitation of 0.5% by weight annually. GHG PTE is calculated to be **5 tpy** for EU 30 and **41 tpy** for EU 31.

**<u>GHG PSD Significance</u>**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 1 is 3,100,454 tons per year of $CO_2e$. Emission rates exceed the SER level for $CO_2e$ of 75,000 tons per year. Thus, a BACT analysis for is required for each piece of equipment that emits $CO_2e$. Establishment of a BACT limit for each emission point that emits $CO_2e$ is also required. Refer to the BACT Analysis for GHG in Section 2.III.F. for a discussion of the BACT for $CO_2e$.

| Emission Unit | $CO_2$ (tpy) | $SF_6$ (tpy) | Methane | Nitrous Oxide | $CO_2e$ |
|---|---|---|---|---|---|
| 18 | 1,456,754 | N/A | 32.42 | 4.17 | 1,458,767 |
| 19 | 1,456,754 | N/A | 32.42 | 4.17 | 1,458,767 |
| 20 | 50,724 | N/A | 0.96 | 0.10 | 50,776 |
| 23 | 4,677 | N/A | 0.088 | 0.0088 | 4,682 |
| 24 | 4,677 | N/A | 0.088 | 0.0088 | 4,682 |
| 29A | 5,994 | N/A | 0.112 | 0.011 | 6,000 |
| 29B | 122 | N/A | 0.0023 | 0.0002 | 123 |
| 29C | 553 | N/A | 0.01 | 0.001 | 554 |
| 21 | 628 | N/A | 0.02 | 0.01 | 630 |

| | | | | | |
|---|---|---|---|---|---|
| 22 | 88 | N/A | 0.0036 | 0.0004 | 89 |
| 30 | N/A | 0.0002 | N/A | N/A | 5 |
| 31 | N/A | 0.0017 | N/A | N/A | 41 |
| **Total:** | 2,980,971 | 0.0019 | 66.12 | 8.48 | **2,985,116** |

## II. Project 2 Emissions

### A. Project PSD Significance

The part of the application associated with modifying emission unit 02 to co-fire natural gas is one of two PSD projects at the facility. East Kentucky Power Cooperative calculated the potential air pollutants emitted by the project for the following regulated NSR pollutants: $NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$, and greenhouse gases (calculated as $CO_2$ equivalent, using the global warming potential values as published in 40 CFR Part 98 Table A-1 to Subpart A in March of 2026).

Potential to emit pollutants at this facility were calculated based on emission factors obtained from US EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, engineering estimates, manufacturer's specifications, and performance testing of existing units. Based on these emission factors, and the assumption of 8,760 hours of operation per year (unless otherwise noted), the potential emissions of regulated NSR pollutants, $NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$, and GHGs exceed the thresholds as indicated in the table, Project 2 – C2 PSD Significance below. A discussion of each pollutant, sources, calculation assumptions, emission factor sources, and the pollutant's PSD significance follows.

***Project 2 – C2 PSD Significance***

| **Pollutant** | **PEI** (tpy) | **Significant Emission Rate** (increase in tpy) | **PSD Significant Emissions Increase?** |
|---|---|---|---|
| $NO_X$ | 785.4 | 40 | Yes |
| CO | 1,242.6 | 100 | Yes |
| VOC | 52.9 | 40 | Yes |
| $SO_2$ | 21.2 | 40 | No |
| PM | 45.40 | 25 | Yes |
| $PM_{10}$ | 33.16 | 15 | Yes |
| $PM_{2.5}$ | 30.88 | 10 | Yes |
| $H_2SO_4$ | 11.2 | 7 | Yes |
| Pb | 0.002 | 0.6 | No |
| GHGs ($CO_2e$) | 967,539.5 | 75,000 | Yes |

A significant emissions increase occurs when a modification causes an increase in emissions of a regulated NSR pollutant equal to or greater than the **significant emission rate (SER)** for that pollutant as specified in 401 KAR 51:001, Section 1(218)(a). EKPC Cooper performed a PSD analysis to determine the **project emissions increase (PEI)** using hybrid applicability tests. For units using the actual-to-potential applicability test, PEI is equal to PTE since actual emissions are equal to zero. Fugitive emissions are included, because EKPC Cooper is included in the 28-source categories listed under 401 KAR 51:001, Section 1(118)(c). There were no projects completed during the 5-year contemporaneous period, so the PEI is equal to the net emissions increase for all NSR pollutants.

For the actual-to-projected actual applicability test, baseline actual emissions (BAE) were determined for all pollutants for the 24-month period between June 2022 and May 2024. To determine PEI, two operating scenarios were analyzed, and BAE was subtracted from the highest emitting scenario for each pollutant. The first scenario is based on combusting coal up to the total heat input (coal and fuel oil) during the baseline period (4,192,207 MMBtu/yr) and natural gas for the remainder of the unit's annual capacity (16,920,211 MMBtu/yr). The second scenario is based on 100% natural gas combustion, (21,112,418 MMBtu/yr). $SO_2$ CEMS data was used to derive an emission factor for controlled $SO_2$ emissions from coal combustion, resulting in a BAE of 74.64 tpy. PAE of scenario 1 results in the highest projected actual emissions of 95.87 tpy, resulting in a PEI of 21.23 tpy of $SO_2$, which is below the SER level of 40 tpy, thus a BACT analysis for $SO_2$ is not necessary.

**B. <u>Nitrogen Oxides ($NO_X$) Emissions</u>**

$NO_X$ emissions originate from the combustion of fossil fuels. At high temperatures during combustion, $NO_X$ is formed by thermal fixation of $N_2$ in the combustion air, oxidation of nitrogen contained in the fuel, and formation of "prompt" nitrogen due to the presence of partially oxidized organic species within the flame. For this project, combustion of coal, fuel oil, and natural gas will primarily form thermal $NO_X$.

**EU 02 – Co-Fired Boiler (C2)**

$NO_X$ formation from the combustion of natural gas and coal in the boiler is mostly in the form of thermal and fuel $NO_X$. Thermal $NO_X$ formation is primarily affected by temperature, concentrations of oxygen and nitrogen, and residence time. Fuel $NO_X$ is the main source of $NO_X$ emissions from coal combustion. Fuel $NO_X$ formation can be controlled by modifying combustion gas temperature, residence time, and turbulence, particularly within and immediately following the flame zone. As the burners in this unit are being modified to switch between burning 100% coal, 100% natural gas, or a combination of the two, the ability to optimize burner conditions is limited, as ideal conditions to minimize fuel $NO_X$ from coal combustion and thermal $NO_X$ from natural gas combustion are different. $NO_x$ control for the boiler consists of low $NO_x$ burners and selective catalytic reduction (SCR).

For this unit, potential actual emissions (PAE) are assumed to be equal to the unit's PTE of the worst-case emissions operating scenario. $NO_x$ emissions are limited to 0.080 lb/MMBtu by the consent decree entered on September 24, 2007. This equates to 2.1 lb/ton when combusting coal and 81.6 lb/MMscf when combusting natural gas, based on site-specific higher heating values of the fuels (23.22 MMBtu/ton for coal, 1060 Btu/scf for natural gas). To determine potential uncontrolled emissions from coal combustion, an estimated control efficiency was back calculated from this limit and the emission factor from AP-42 Table 1.1-3 for PC, dry bottom, wall-fired bituminous, pre-NSPS boilers for coal. Similarly, a control efficiency was back calculated for natural gas combustion using the emission factor from AP-42 Table 1.4-1 Large Wall-Fired Boilers (>100 MMBtu/hr). For $NO_x$, operating scenario 2 (natural gas firing) provides the worst-case emissions and PAE is estimated to be 877.60 tpy. BAE for $NO_x$ was determined to be 94.72 tpy, from

CEMS data for the period between June 2022 and May 2024. As C2 is an existing unit, the PEI is the difference between PAE and BAE and is 782.88 tpy.

**EU 17 – Natural Gas-Fired Dewpoint Heater**
$NO_X$ emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. $NO_X$ control for the boiler consists of low $NO_X$ burners (LNBs) and good combustion and operations practices. $NO_X$ emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Controlled - Low $NO_X$ Burners" for small boilers less than 100 MMBtu/hr. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. $NO_X$ PTE is calculated to be 2.50 tpy for EU 17. As this is a new unit, the PTE is added to the Unit 2 PAE to determine the PEI.

**$NO_X$ PSD Significance**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the $NO_X$ project emissions increase (PEI) for Project 2 is 785.38 tons per year. These emission rates exceed the SER level for $NO_x$ of 40 tons per year. Thus, a BACT analysis for $NO_X$ is required for each piece of equipment that emits $NO_X$. Establishment of a BACT limit for each emission point that emits $NO_X$ is also required. Refer to the BACT Analysis for $NO_X$ in Section 2.III.A. of this document for a discussion of the BACT for $NO_X$.

| Emission Unit | $NO_x$ PEI (tpy) |
|---|---|
| 02 | 782.88 |
| 17 | 2.50 |
| **Total:** | **785.38** |

## C. Carbon Monoxide (CO) Emissions
CO is formed from the incomplete combustion of fuels. The unburned carbon in the fuel is oxidized to form CO instead of $CO_2$. Temperature and residence time in the combustion zone are key factors for CO emissions.

**EU 02 – Co-Fired Boiler (C2)**
For this unit, PAE are assumed to be equal to the unit's PTE of the worst-case emissions operating scenario. CO emissions when combusting coal are calculated to be 0.447 lb/ton, from AP-42 Table 1.1-3. When co-firing or combusting natural gas, emissions are calculated to be 127.2 lb/MMscf, from the recommended BACT Limit. For CO, operating scenario 2 (100% natural gas firing) is considered the worst-case scenario and results in a PAE of 1,278.85 tpy. BAE are calculated as 40.47 tpy, based on the emission factor and hours of operation of the unit during the 24-month period between June 2022 and May 2024. PEI, the difference between PAE and BAE, was calculated to be 1,238.38 tpy. CO control for the boiler consists of good combustion and operations practices.

**EU 17 – Natural Gas-Fired Dewpoint Heater**
CO emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. CO control for the boiler consists of good combustion and operations practices. CO emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-1 "Controlled - Low $NO_X$ Burners." AP-42 emission factors utilize a natural gas heat

content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. CO PTE is 4.20 tpy.

**CO PSD Significance**

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the CO PEI for Project 2 is 1,242.58 tons per year of CO. These emission rates exceed the SER level for CO of 100 tons per year. Thus, a BACT analysis is required for each piece of equipment that emits CO. Establishment of a BACT limit for each emission point that emits CO is also required. Refer to the BACT Analysis for CO in Section 2.III.B. in this document for a discussion of the BACT for CO.

| Emission Unit | CO (tpy) |
|---|---|
| 02 | 1,238.4 |
| 17 | 4.2 |
| **Total:** | **1,242.6** |

**D. Volatile Organic Compounds (VOC) Emissions**

VOC emissions are formed from the incomplete combustion of fossil fuels and the storage and transmission of fuels. Temperature and residence time are key factors for VOC formation.

**EU 02 – Co-Fired Boiler (C2)**

Potential actual emissions (PAE) are assumed to be equal to the unit's PTE from the worst-case emissions operating scenario. VOC emissions while combusting coal are calculated using an emission factor of 0.054 lb/ton from AP-42 Table 1.1-3. When combusting 100% natural gas, emissions are calculated using 5.72 lb/MMscf from AP-42 Table 1.4-2. For VOC, operating scenario 2 (natural gas firing) provides the worst-case emissions scenario and PAE is estimated to be 57.46 tpy. BAE for VOC was determined to be 4.83 tpy, from the emission factor and hours of operation of the unit for the 24-month period between June 2022 and May 2024. PEI is the difference between PAE and BAE and was calculated to be 52.63 tpy. VOC controls for the boiler consists of good combustion and operations practices.

**EU 17 – Natural Gas-Fired Dewpoint Heater**

VOC emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. VOC control for the boiler consists of good combustion and operations practices. VOC emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. VOC PTE is calculated to be 0.28 tpy for EU 17.

**VOC PSD Significance**

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 2 is 52.90 tons per year of VOC. These emission rates exceed the SER level for VOC of 40 tons per year. Thus, a BACT analysis for VOC is required for each piece of equipment that emits VOC. Establishment of a BACT limit for the emission of VOC for each emission point that emits VOC is also required. Refer to the BACT Analysis for VOC, below, for a discussion of the BACT for VOC.

| Emission Unit | VOC (tpy) |
|---|---|
| 02 | 52.6 |
| 17 | 0.3 |
| **Total:** | **52.9** |

E. **Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions**

PM, $PM_{10}$, and $PM_{2.5}$ are regulated NSR pollutants. $PM_{10}$ has an aerodynamic diameter of 10 microns or less, and $PM_{2.5}$ has an aerodynamic diameter of 2.5 microns or less. Both filterable and condensable components are required to be included in applicability determinations and in establishing emissions limitations for $PM_{10}$ and $PM_{2.5}$. Filterable PM is defined as particles directly emitted as a solid or liquid at stack conditions and captured on the filter of a stack test train. Condensable PM is material that is in a vapor phase at stack conditions that condenses to form a solid or liquid immediately after discharge from a stack.

Particulates, often discharged through stacks or vents, may also be emitted in a fugitive form. Under 401 KAR 51:001, fugitive emissions are defined as those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Fugitive emissions are counted toward emissions totals, as EKPC Cooper Station is a listed 28-source category. When speciation of particulate type is unavailable, all particulate is assumed to be part of the same size fraction for conservative purposes when calculating the Potential to Emit.

$PM/PM_{10}/PM_{2.5}$ emissions from the boiler consist of both filterable and condensable particulate matter. When combusting coal, filterable PM emissions include ash and unburned carbon from incomplete combustion. The boiler system achieves high combustion efficiency such that filterable PM emissions are primarily composed of inorganic ash. Some filterable PM emissions will occur from soot blowing operations, to remove ash from the boiler and exhaust. Filterable PM emissions from the combustion of natural gas are low compared to other fuel sources and are primarily composed of larger molecular weight hydrocarbons that do not fully combust.

Condensable PM is the portion of particulate matter that exhausts in gaseous form but condenses to aerosol particulate matter when in contact with ambient air. Sulfur and the resultant sulfate formation, $NO_X$ oxidizing to form nitrate, and high molecular weight organics make up condensable PM emissions. All condensable PM is less than 2.5 µm, and therefore, included as $PM_{10}$ and $PM_{2.5}$. As unreacted ammonia in an SCR forms ammonium sulfates, these sulfates cause an increase in condensable PM emissions. For boilers operating an SCR, it is expected that $PM_{10}$ and $PM_{2.5}$ emissions will be greater than for boilers without an SCR.

**EU 02 – Co-Fired Boiler (C2)**

PAE are assumed to be equal to the unit's PTE of the worst-case emissions operating scenario. PM, $PM_{10}$, and $PM_{2.5}$ emissions from coal combustion are estimated to be 0.697 lb/ton, 0.678 lb/ton, and 0.588 lb/ton respectively, sourced from AP-42 Table 1.1-5.

These emission factors account for both condensable and filterable particulate matter, and controls for the filterable portion of particulate matter. PM, $PM_{10}$, and $PM_{2.5}$ emissions from natural gas combustion are estimated to be 3.61 lb/MMscf each, calculated from AP-42 Table 1.4-2 and the EPA Speciate database. This emission factor represents the sum of filterable and condensable PM from natural gas combustion, and controls for the filterable portion of particulate matter. For PM, $PM_{10}$ and $PM_{2.5}$, operating scenario 1 (co-firing coal and natural gas) provides the worst-case emissions scenario and PAE is estimated to be 91.66 tpy, 89.99 tpy, and 81.81 tpy respectively. BAE for PM/$PM_{10}$/$PM_{2.5}$, based on annual performance testing on the unit was determined to be 50.68 tpy, 58.11 tpy, and 51.21 tpy, respectively. PEI is the difference between PAE and BAE and is 40.98 tpy, 31.88 tpy and 30.60 tpy for $PMM_{10}$/$PM_{2.5}$, respectively. PM/$PM_{10}$/$PM_{2.5}$ control for the boiler consists of a pulse jet fabric filter and dry flue gas desulfurization.

**EU 17 – Natural Gas-Fired Dewpoint Heater**
PM/$PM_{10}$/$PM_{2.5}$ emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. The PM/$PM_{10}$/$PM_{2.5}$ emissions typically consist of larger molecular weight hydrocarbons that are not fully combusted upon exiting the boiler. Maintenance issues and poor air/fuel mixing contribute to filterable PM emissions from natural gas combustion. PM/$PM_{10}$/$PM_{2.5}$ control for this boiler consists of good combustion operating and maintenance practices and burning pipeline quality natural gas. PM/$PM_{10}$/$PM_{2.5}$ emissions are calculated using EPA's AP-42 Ch. 1.4 Table 1.4-2 and the EPA Speciate Database. AP-42 emission factors utilize a natural gas heat content of 1,020 Btu/scf while the design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. PM/$PM_{10}$/$PM_{2.5}$ PTE is calculated to be 0.17 tpy for EU 17.

**EU 35 – Coal Storage and Handling Operations for Coal Stockpile #2**
PM/$PM_{10}$/$PM_{2.5}$ emissions from coal storage and handling are generated from the transportation of vehicles on stockpile roadways, wind erosion of the stockpile, and material becoming airborne while dumping coal. Control for coal handling and storage consists of wet suppression and good housekeeping practices to minimize fugitive dust emissions.

PM/$PM_{10}$/$PM_{2.5}$ emissions are calculated according to the methodology described by the EPA Document "Control of Open Fugitive Dust Sources" for the stockpile, $PM_{10}$ is assumed to be 50% of PM, and $PM_{2.5}$ is assumed to be 7.5% of PM. Controlled emissions from the stockpile for PM/$PM_{10}$/$PM_{2.5}$ are calculated to be 0.031 tpy, 0.014 tpy, and 2.19E-03 tpy, respectively.

Emissions from coal unloading are calculated according to the methodology in AP-42 Chapter 13.2.4 for Aggregate Handling and Storage Piles. The emission factor is then doubled to account for being handled by both the truck and front-end loader. Controlled emissions of PM/$PM_{10}$/$PM_{2.5}$ are estimated to be 0.018 tpy, 8.54E-3 tpy, and 1.29E-3 tpy, respectively.

Emission from truck and front-end loader traffic on the coal pile are calculated according to the methodology in AP-42 Section 13.2.2 for unpaved roadways. Controlled emissions of PM/$PM_{10}$/$PM_{2.5}$ are estimated to be 4.21 tpy, 1.09 tpy, and 0.11 tpy, respectively.

The sum of $PM/PM_{10}.PM_{2.5}$ emissions from coal handling are:

**$PM/PM_{10}/PM_{2.5}$ PSD Significance**
The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 2 is 41.15/32.04/30.77 tons per year of $PM/PM_{10}/PM_{2.5}$, respectively. These emission rates exceed the SER level for $PM/PM_{10}/PM_{2.5}$ of 25/15/10 tons per year, respectively. Thus, a BACT analysis is required for each piece of equipment that emits $PM/PM_{10}/PM_{2.5}$. Establishment of a BACT limit for the emission of $PM/PM_{10}/PM_{2.5}$ for each emission point that emits $PM/PM_{10}/PM_{2.5}$ is also required. Refer to the BACT Analysis for $PM/PM_{10}/PM_{2.5}$, below, for a discussion of the BACT for VOC.

| Emission Unit | PM (tpy) | $PM_{10}$ (tpy) | $PM_{2.5}$ (tpy) |
|---|---|---|---|
| 02 | 40.98 | 31.88 | 30.60 |
| 17 | 0.17 | 0.17 | 0.17 |
| 35 | 4.25 | 1.11 | 0.11 |
| **Total:** | **45.40** | **33.16** | **30.88** |

**F. Sulfuric Acid ($H_2SO_4$) Emissions**
Sulfuric Acid Mist (SAM or $H_2SO_4$) emissions are formed when sulfur-containing compounds are oxidized to sulfur trioxide ($SO_3$), which then combines with water vapor to form fine droplets or aerosols of sulfuric acid. This conversion is influenced by the sulfur content in the fuel, ambient temperature, relative humidity, evaporative cooling operations, duct burner operations, oxidation over the oxidation catalyst, oxidation within the SCR, available moisture, ammonia slip concentration and acid dew point. Any high-temperature combustion source that burns fossil fuel is a source of Sulfuric Acid Mist.

**EU 02 – Co-Fired Boiler (C2)**
PAE is assumed to be equal to the unit's PTE for the worst-case emissions operating scenario. $H_2SO_4$ emissions are a result of the reaction between $SO_3$ and water. $SO_3$ is a result of the oxidation of fuel bound sulfur during combustion and the downstream SCR catalyst. The driving factors for the formation of $SO_3$ and therefore $H_2SO_4$ are the sulfur content of the fuel, chemical parameters of the SCR, air preheater, and CFB scrubber. $H_2SO_4$ emissions are estimated to be 0.13 lb/ton when combusting coal and 0.011 lb/MMscf when combusting natural gas, each calculated utilizing the EPRI model. The full calculations for the EPRI model can be found in the NOD Response submitted on September 4, 2025. For $H_2SO_4$, scenario 1 (co-firing coal and natural gas) provides the worst-case emissions scenario and PAE is estimated to be 11.64 tpy. BAE for $H_2SO_4$ was determined to be 0.49 tpy from the stack test emission factor and coal throughput for the 24-month period between May 2022 and June 2024. PEI is the difference between PAE and BAE and is 11.15 tpy.

**EU 17 – Natural Gas-Fired Dewpoint Heater**
$H_2SO_4$ emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. $H_2SO_4$ control for this boiler consists of burning pipeline quality natural gas along with good combustion and operations practices. $H_2SO_4$ emissions are calculated using the maximum allowable natural gas sulfur content of 0.5 gr/100scf and the site-specific heat content of 1,060 Btu/scf. $H_2SO_4$ PTE is calculated to be 0.005 tpy.

**Sulfuric Acid ($H_2SO_4$) PSD Significance**

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the projected emissions increase (PEI) for Project 2 is 11.16 tons per year. These emission rates exceed the SER level for $H_2SO_4$ of 7 tons per year. Thus, a BACT analysis is required for each piece of equipment that emits $H_2SO_4$. Establishment of a BACT limit for each emission point that emits $H_2SO_4$ is also required. Refer to the BACT Analysis for $H_2SO_4$ under Section 2.III.E. of this document for a discussion of the BACT for $H_2SO_4$.

| Emission Unit | $H_2SO_4$ (tpy) |
|---|---|
| 02 | 11.15 |
| 17 | 0.005 |
| **Total:** | **11.16** |

## G. Greenhouse Gas (GHG) Emissions

GHG emissions originate from the combustion of fossil fuels. The majority of greenhouse gas emissions from the fossil-fuel fired boiler are in the form of $CO_2$. Emissions from methane and nitrous oxide are converted to the equivalent amount of $CO_2$ ($CO_2e$) that would result in the same global warming potential by multiplying by a factor of 28 for methane and 265 for $N_2O$, as codified in Appendix A-1 of 40 CFR part 98 effective January 1, 2025. The production of $CO_2$ occurs from a reaction between carbon and oxygen in the air and proceeds stoichiometrically.

**EU 02 – Co-Fired Boiler (C2)**

PAE is assumed to be equal to the unit's PTE of the worst-case emissions operating scenario. Emission factors used for $CO_2$, methane, and nitrous oxide from coal combustion are 4,776 lb/ton, 0.56 lb/ton, and 0.08 lb/ton, respectively. Emission factors used for $CO_2$, methane, and nitrous oxide from natural gas combustion are estimated to be 120,017 lb/MMscf, 2.26 lb/MMscf, and 0.22 lb/MMscf, respectively, all sourced from 40 CFR 98 Tables C-1 and C-2. For $CO_2$, methane, and nitrous oxide, scenario 1 (co-firing coal and natural gas) provides the worst-case emissions scenario and PAE is 1,389,018 tpy, 68.90 tpy and 9.2 tpy respectively. BAE for $CO_2$ was based on CEMS data for the unit and determined to be 431,631 tpy. BAE for methane and nitrous oxide were calculated as 50.67 tpy and 7.37 tpy, respectively using the emission factors and hours of operation for the unit. Values for methane and $N_2O$ were then converted to $CO_2e$ using the global warming potentials published in 40 CFR 98, Subpart A Table A-1. PEI is the difference between PAE and BAE and was determined to be 961,756 tpy of $CO_2e$.

**EU 17 – Natural Gas-Fired Dewpoint Heater**

GHG emissions from the natural gas preheater are generated from burning natural gas at 11.65 MMBtu/hr. GHG control for these boilers consists of good combustion and operations practices and burning pipeline quality natural gas. GHG emission factors from 40 CFR Part 98, Subpart C, Tables C-1 & C-2 utilize a natural gas heat content of 1,026 Btu/scf from 40 CFR 98. The design rate utilizes the site-specific heat content of 1,060 Btu/scf. Emission factors were converted to utilize the site-specific heat content for consistency with the design rate. $CO_2$, Methane ($CH_4$), Nitrous Oxide, and GHG emissions are listed in the table below.

| Emission Unit | $CO_2$ (tpy) | Methane ($CH_4$) (tpy) | Nitrous Oxide (tpy) | GHG (tpy) |
|---|---|---|---|---|
| 17 | 5,968 | 0.112 | 0.011 | 5,975 |

**GHG PSD Significance**

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, show the PEI for Project 2 is 967,539 tons per year of $CO_2e$, exceeding the SER level for $CO_2e$ of 75,000 tons per year. Thus, a BACT analysis is required for each piece of equipment that emits $CO_2e$. Establishment of a BACT limit for each emission point that emits $CO_2e$ is also required. Refer to the BACT Analysis for $CO_2e$ in Section 2.III.F. of this document for a discussion of the BACT for $CO_2e$.

| Emission Unit | $CO_2$ (tpy) | Methane ($CH_4$) (tpy) | Nitrous Oxide (tpy) | GHG (tpy) |
|---|---|---|---|---|
| 02 | 960,760 | 18.33 | 1.84 | 967,539.5 |
| 17 | 5,968 | 0.112 | 0.011 | 5,975 |
| **Total** | | | | |

## III. BACT Analysis

The following is a summary of the various BACT analyses, and the limits and requirements attributed to each emission unit. This discussion is separated into parts, on a per pollutant basis, following a top-down approach. At the beginning of each pollutant section there will be an overview of the control technologies and methods reviewed for that pollutant. In an effort to identify all potentially applicable emission control technologies, a broad range of sources were searched, including:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database
- Federal and State NSR permits and BACT determinations for similar sources
- Engineering experience with similar control applications
- Information provided by air pollution control equipment vendors
- Review of technical reports, journals, and air pollution control seminars.

The technology summary will be followed by a summary of the BACT limit for each unit on a per pollutant basis. Some units will be grouped together for convenience. For each emission unit that has the potential to emit the pollutant, technically infeasible options are eliminated, remaining control technologies are ranked, options that provide the best control are evaluated to determine economic feasibility, and BACT is selected. The permit has requirements to ensure the BACT limits are federally enforceable. Section 3 of this document outlines the testing, monitoring, recordkeeping, and reporting requirements needed to demonstrate compliance with the BACT limits for each emission unit.

### A. BACT Analysis for $NO_X$

**Technologies Reviewed:**

*Dry Low $NO_X$ (DLN) Combustors*

DLN Combustors pre-mix air and natural gas into a lean mixture prior to injection into the combustion turbine, significantly reducing peak flame temperature and thermal $NO_X$ formation.

*Water/Steam Injection*
Water or steam injection involves the injection of water or steam into the primary combustion zone. The injected fluid provides a heat sink that absorbs some of the heat of combustion. This reduces the combustion temperature, thereby reducing the formation of thermal $NO_X$.

*Good Combustion and Operations Practices (GCOP)Plan*
Good combustion and operations practices are operating practices and principles that allow the equipment to operate as efficiently as possible. Good combustion practices such as minimizing combustion temperature and reducing excess oxygen can help limit $NO_X$ formation. However, a balance must be achieved to avoid resulting in increased CO formation. Control systems automatically adjust operating parameters to enhance the combustion efficiency.

*$EM_X$™/$SCONO_X$™/METEOR™*
$EM_X$™, $SCONO_X$™, and METEOR™ are multi-pollutant post combustion control technologies. The control efficiency for $NO_X$ for these control technologies is about the same or lower than SCRs. $EM_X$™/$SCONO_X$™ removes $NO_X$ without using a reagent, such as $NH_3$, whereas METEOR™ uses ammonia.

*Selective Catalytic Reduction (SCR)*
SCR is a post-combustion control that uses anhydrous ammonia, aqueous ammonia, or dissolved urea in the presence of a catalyst to convert $NO_X$ into nitrogen and water. The catalyst acts to lower the temperature necessary to reduce $NO_X$ to diatomic nitrogen. For systems that use ammonia, the following reduction reactions take place:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$
$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

Ammonia slip may occur, usually at less than 5 ppm, in which case excess ammonia reacts with sulfuric acid to form salts, which precipitate out of the gas stream and corrode the catalyst and CT equipment downstream of the SCR. High sulfur fuels have a greater potential to oxidize into sulfuric acid than natural gas. For SCR with urea injection, the ammonia reacting with the $NO_X$ is produced as a result of the hydrolysis of the urea in the flue gas.

The $NO_X$ reduction efficiency depends on the stoichiometric injection of ammonia, type of catalyst used, and the exhaust gas temperature. $NO_X$ destruction efficiencies are typically 90% or more.

*Selective Non-Catalytic Reduction (SNCR)*
SNCR is a post-combustion control similar to SCRs but without the presence of a catalyst to lower the activation energy needed to reduce $NO_X$. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the $NO_X$ to nitrogen and water. $NO_X$ destruction efficiencies range from 30-50%. Due to the absence of a catalyst, the operating temperature is required to be much higher than what's required for SCR systems. Peak efficiency temperatures range from 1,600 to 2,000 degrees Fahrenheit to avoid ammonia slip. Operating below this temperature range results

in ammonia slip. Operating above this range results in ammonia oxidation which forms additional $NO_X$.

*Ultra Low-$NO_X$ Burners (Ultra LNBs or ULNB)*
Ultra LNBs are designed to control fuel and air mixing in order to create larger and more branched flames. This lowers the flame temperature and as a result, reduces thermal $NO_X$ formation. Ultra LNBs also reduce the amount of oxygen available in the flame which improves burner efficiency. Low $NO_X$ levels are achieved by introducing fuel primarily to the pre-mix zones and reducing the amount of fuel combusted from the pilot nozzle.

*Low-$NO_X$ Burners (LNBs)/ Over-Fire Air (OFA)*
Low $NO_X$ Burners provide a stable flame with different zones and lower temperatures to mitigate $NO_X$ formation. Over-Fire Air can be used with a fuel-rich mixture to complete primary combustion and mitigate the formation of $NO_X$. LNBs provide a control efficiency between 38% and 63%. LNBs and OFA can result in CO and VOC emissions increases and unburned carbon in the fly ash, due to the lowered combustion temperatures.

*Combustion Design Controls*
Proper equipment design and operation are important in minimizing incomplete combustion by allowing for sufficient residence time at high temperatures as well as turbulence to allow for complete mixing. Combustion zone temperature and residence time have an opposite effect on CO emissions versus $NO_X$ emissions. It is critical to optimize oxygen availability with input air while controlling temperature to minimize $NO_X$ formation.

*Rich Reagent Injection (RRI)*
RRI was initially developed for coal-fired cyclone boilers. It requires a fuel-rich environment. RRI functions similarly to SNCR, but the reagent injection occurs at higher gas temperatures (2400-3100°F) within the combustion zone of the lower furnace.

*Flue Gas Reheat*
During low load, startup, and shutdown, flue gas reheat increases the temperature, which can make SCR operation technically feasible at lower loads. This includes the installation of flue gas reheat burners or an economizer bypass.

*Oxygen Enhanced Combustion*
Oxygen enhanced combustion systems use a cryogenic process to supply pure oxygen and are designed for a conventional supercritical pulverized-coal boiler.

*Flue Gas Recirculation (FGR)*
The FGR process recirculates some of the flue gas back into the boilers. The recirculated gas reduces combustion temperatures by acting as a thermal diluent. The recirculated gas also dilutes the combustion reactants, reducing the excess air requirements and reducing the concentration of oxygen and nitrogen in the combustion zone.

*Economizer Bypass*
An economizer bypass enables higher flue gas exhaust temperatures to reach the downstream SCRs, potentially allowing the SCRs to operate at low loads, startups and shutdowns.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of SCR Technology, DLN Combustors (when combusting natural gas), water injection (when combusting fuel oil), and GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities (EU 18 and 19):

| Emission Point | BACT | | NOx Emission Limitation | | Compliance Demonstration |
|---|---|---|---|---|---|
| | | | BACT Limit for $NO_X$ | Averaging Period | |
| 18 & 19 | When Combusting Natural Gas | SCR, DLN, & GCOP | 2.0 ppmvd at 15% $O_2$, excluding SU/SD | 24-hour rolling average | $NO_X$ CEMS |
| | When Combusting ULSFO | SCR, Water Injection, & GCOP | 4.5 ppmvd at 15% $O_2$, excluding SU/SD | 24-hour rolling average | $NO_X$ CEMS |
| | Both Fuels | | 169 tpy, including SU/SD | 12-month rolling total | $NO_X$ CEMS |

**Technologies:**
The following technologies were reviewed for the above source: DLN Combustors (DLN or Dry Low-$NO_X$ Burners), Water/Steam Injection, GCOP, $EM_X$™/$SCONO_X$™/METEOR™, Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR).

**Analysis**:
DLN cannot be used during fuel oil operation or low load natural gas operation and is therefore technically infeasible for fuel oil operation. Water/steam injection is commonly used to control $NO_X$ emissions during fuel oil operation. Water/steam injection is not as effective when firing natural gas and cannot be used in conjunction with DLN because the combination would create unstable combustion and increase CO emissions. Water/steam injection is technically infeasible for natural gas operation. $EM_X$™ and $SCONO_X$™ technology have not been used commercially for large combustion turbines due to engineering challenges and is considered technically infeasible. METEOR™ has not been used commercially for large combustion turbines due to engineering challenges while also not providing a greater reduction efficiency than SCR and is considered technically infeasible. The required temperature range for effective SNCR operation (1,600 – 2,000°F) is above the peak exhaust temperature for the turbines. SNCR is considered technically infeasible.

SCR as a post-combustion control, DLN for natural gas firing, Water/steam injection for fuel oil firing, and GCOP for both fuel operating modes have been selected as BACT for these units.

The post-combustion controls take longer to achieve the rated destruction efficiency than the turbine takes to reach steady-state, so when the system is starting up and shutting down, emissions of $NO_X$ are considered uncontrolled.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Ultra LNBs and GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for $NO_X$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | Ultra LNBs & GCOP | 0.011 lb/MMBtu | 3-hour average | Performance Testing |
| | | 5.0 tpy | 12-mponth rolling average | |

**Technologies:**
The following technologies were reviewed for the above source:
$EM_X$™/$SCONO_X$™/METEOR™, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Ultra Low-$NO_X$ Burners (Ultra LNBs), and GCOP.

**Analysis**:
$EM_X$™, $SCONO_X$™, and METEOR™ technology has not been used commercially on small boilers and is considered technically infeasible. The remaining control technologies are ranked by control efficiency below:

| Rank | Control Technology | Potential Control Efficiency (%) |
|---|---|---|
| 1 | SCR | 90 |
| 2 | Ultra LNB | 70 |
| 3 | SNCR | 60 |
| 4 | GCOP | Varies |

SCR can be applied as a post combustion control for some larger gas-fired heaters but is not feasible for application to a small gas-fired heater such as the proposed boiler. A review of the RBLC database found that no natural gas fired boilers less than 100 MMBtu/hr have installed an SCR. EKPC also prepared a cost estimate and found that the annualized total annual cost for an SCR would be $27,230 per ton controlled in 2024 dollars. SCR is determined to be infeasible for this unit.

SNCR is capable of achieving 60% control for the boiler, however is not feasible for application to a small gas-fired heater such as the proposed boiler. A review of the RBLC database found that no natural gas fired boilers less than 100 MMBtu/hr have installed an SNCR. EKPC also prepared a cost estimate and found that the annualized total annual cost for an SNCR would be $15,230 per ton controlled in 2024 dollars. SNCR is determined to be infeasible for this unit.

Therefore, Ultra low-$NO_X$ burners and good combustion and operations practices are selected as BACT for this unit.

 

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low-$NO_X$ Burners and GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for $NO_X$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 & 24 | Low-$NO_X$ burners & GCOP | 0.05 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 2.0 tpy, each | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Low-$NO_X$ Burners (LNBs), and GCOP.

**Analysis**:
The flue gas temperature range for optimum SCR and SNCR operation is 700°F to 750°F. The exhaust temperature for these heaters is approximately 300°F, which is outside the operating range of SCR and SNCR. SCR and SNCR are technically infeasible. LNBs provide a control efficiency between 38% and 63% and are commercially available and economically feasible for these boilers. Therefore, Low-$NO_X$ burners and Good Combustion and Operations Practices are selected as BACT for these units.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for $NO_X$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | GCOP | 0.1 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |

**Technologies:**
The following technologies were reviewed for the above source: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Low-$NO_X$ Burners (LNBs), and GCOP.

**Analysis**:
The flue gas temperature range for optimum SCR and SNCR operation is 700°F to 750°F. The exhaust temperature for these heaters is approximately 300°F, which is outside the operating range of SCR and SNCR. SCR and SNCR are technically infeasible. A review of the RBLC database found that no gas-fired heaters less than 10 MMBtu/hr have post combustion $NO_X$ controls. Therefore, good combustion and operations practices is selected as BACT for these units.

**EU 21 CCGT Emergency Generator Engine**
**EU 22 CCGT Emergency Fire Pump Engine**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for $NO_X$ + VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 21 | GCOP | 4.8 g/HP-hr | N/A | Purchase a certified engine |
| 22 | | 3.0 g/HP-hr | | |

**Technologies:**
The following technologies were reviewed for the above source: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Combustion Design Controls, and GCOP.

**Analysis**:
While post-combustion $NO_X$ controls like SCR and SNCR are technically feasible for emergency engines, the costs associated to reduce such a small amount of $NO_X$ would be prohibitive. In addition, the operation of this equipment will be limited to emergency events and required routine testing. SCR and SNCR require steady state operation to be effective. Maintenance checks and readiness testing requires the engine to be turned on for a short period of time, typically one hour. The emission rate varies during startup and shutdown and the SCR or SNCR would have ammonia slip or urea released into the atmosphere during this time, resulting in negative environmental impacts. Therefore, purchasing an engine certified to meet the requirements of 40 CFR Part 60 Subpart IIII for $NO_X$ + NMHC (Non-Methane Hydrocarbons, or VOC) and GCOP are selected as BACT for this unit.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of SCR and GCOP constitutes BACT for $NO_X$. The unit has an existing SCR installed that will operate during periods of 100% coal combustion, 100% natural gas combustion, or a combination of the two. The following BACT standards apply to EU 02 at all times, including startup and shutdown:

| Emission Point | BACT | BACT Limit for $NO_X$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 02 | SCR & GCOP | 0.080 lb/MMBtu | 30-day rolling | $NO_X$ CEMS |
| | | 878 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: LNB/Over-Fire Air, SNCR, Rich Reagent Injection (RRI), Flue Gas Reheat, Oxygen Enhanced Combustion, FGR, and Economizer Bypass.

**Analysis**:
The vendor only has one option for converting the existing coal boiler to have the ability to co-fire natural gas while maintaining the ability to combust 100% coal. This technology does not meet the metrics for LNB performance during NG combustion. Adding an OFA would require EKPC to modify the current primary and flue gas fan control methods. In addition to being a large-scale change in the boiler operation, OFA would not provide greater $NO_X$ emission reductions than the existing SCR. RRI is not considered to be feasible for a wall-fired boiler, as it was developed for use in cyclone boilers. Oxygen Enhanced Combustion is designed for a supercritical system, which unit 2 is not. Installation of an economizer bypass would constitute a major modification of the unit and impact the heat transfer, energy efficiency, and net electrical generation of the unit; thus, it is technically infeasible. An FGR arrangement that would be appropriate for coal combustion would not function as a $NO_X$ control technology; the arrangement that would be appropriate for controlling emissions during natural gas combustion would be inappropriate for times of coal combustion. Additionally, it is not feasible to have a system that would operate only during certain operating scenarios, so FGR is not a feasible control technology. Of the remaining control technologies, SCR has the highest efficiency and is already installed on the unit.

**EU 17 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low-$NO_X$ Burners and GCOP constitutes BACT for $NO_X$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for $NO_X$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | Low-$NO_X$ burners & GCOP | 0.05 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 2.5 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Low-$NO_X$ Burners (LNBs), and GCOP.

**Analysis**:
The flue gas temperature range for optimum SCR and SNCR operation is 700°F to 750°F. The exhaust temperature for these heaters is approximately 300°F, which is outside the operating range of SCR and SNCR. SCR and SNCR are technically infeasible. LNBs provide a control efficiency between 38% and 63% and are commercially available and

economically feasible for these boilers. Therefore, Low-$NO_X$ burners and GCOP are selected as BACT for these units.

**B. <u>BACT Analysis for CO</u>**

**Technologies Reviewed:**

*<u>Oxidation Catalyst (OxCat) Technology</u>*

OxCat technology consists of a catalyst bed of precious metals that promotes the oxidation of CO to $CO_2$ without the use of additional reaction accelerants (such as ammonia or urea used in an SCR for $NO_X$ control). The basic chemical reactions in the exhaust stream from an oxidation catalyst are as follows:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2$$

$$C_nH_m + \left(n + \frac{m}{4}\right)O_2 \rightarrow n\,CO_2 + \left(\frac{m}{2}\right)H_2O$$

$$C_nH_mO + \left(n + \frac{m}{4} - 0.5\right)O_2 \rightarrow n\,CO_2 + \left(\frac{m}{2}\right)H_2O$$

$$2H_2 + O_2 \rightarrow 2H_2O$$

Different catalyst materials can be used depending on the gas stream, with precious metals such as platinum, palladium, or rhodium being most common. Destruction efficiencies for CO are typically 90% or more, depending on the catalyst used, operating temperature, and the presence of other pollutants.

*<u>$EM_X$™/$SCONO_X$™/METEOR™</u>*

$EM_X$™, $SCONO_X$™, and METEOR™ are multi-pollutant post combustion control technologies that use a coated oxidation catalyst to control CO emissions without a reagent such as $NH_3$. The $EM_X$™/$SCONO_X$™ catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. All three systems use an oxidation catalyst that provides an equivalent level of control for CO emissions to other oxidation catalysts.

*<u>Good Combustion and Operations Practices (GCOP) Plan</u>*

Good combustion and operations practices are operating practices and principles that allow the equipment to operate as efficiently as possible. It includes equipment design and operation consistent with good combustion practices to minimize incomplete combustion. CO emissions are increased when there is poor mixing (not enough turbulence) and/or there is not enough air in the mix. Optimizing the air/fuel mixture and combustion temperature allows the carbon in the fuel to oxidize to $CO_2$ instead of CO. Higher combustion temperatures tend to reduce CO formation but may result in higher $NO_X$ formation.

*<u>Diesel Oxidation Catalyst (DOC)</u>*

A Diesel Oxidation Catalyst (DOC) unit is a “flow through” control device for stationary diesel engines. The DOC contains a honeycomb-like structure or substrate with a large surface area. The structure is coated with an active catalyst layer that reduces CO and VOC emissions. The catalyst enables CO, gaseous hydrocarbons, and liquid hydrocarbon particles (unburned fuel and oil) in the exhaust to oxidize into $CO_2$ and $H_2O$. The CO and VOC reduction varies depending on the catalyst formulations in the DOC. DOC control efficiency can be up to 90% for CO and VOC.

*Combustion Design Controls*
Proper equipment design and operation are important in minimizing incomplete combustion by allowing for sufficient residence time at high temperatures as well as turbulence to mitigate incomplete mixing. Combustion zone temperature and residence time have an opposite effect on CO emissions versus $NO_X$ emissions.

*Thermal Oxidation*
A thermal oxidizer reduces the amount of CO present in an exhaust stream by supplying sufficient combustion air and supplemental fuel at a suitable temperature to allow for oxidation of CO.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Oxidation Catalyst and GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 18 & 19 (Both fuels) | OxCat and GCOP | 2 ppmvd at 15% $O_2$, excluding SU/SD | 24-hour rolling average | CO CEMS |
| | Both Fuels | 2,805 tpy, including SU/SD | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst, $EM_X$™/$SCONO_X$™/METEOR™, and GCOP.

**Analysis**:
$EM_X$™/$SCONO_X$™/METEOR™ technologies have not been used commercially for large combustion turbines due to engineering challenges and are considered technically infeasible. Oxidation Catalysts (OxCat) typically operate within a temperature range of 600°F to 800°F. A combined cycle turbine with a heat recovery steam generator (HRSG) lowers the exhaust gas temperature into the oxidation catalyst’s operating range. While the fuel used impacts the effectiveness of an OxCat, a properly designed OxCat is capable of operating during both natural gas and fuel oil operation. Modern turbine control systems can implement good combustion practices by using computer-based systems to adjust operating parameters automatically.

The post-combustion controls take longer to achieve the rated destruction efficiency than the turbine takes to reach steady state, so when the system is starting up and shutting down, emissions of CO are considered uncontrolled.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Oxidation Catalyst and GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | OxCat and GCOP | 0.0003 lb/MMBtu | 3-hour average | Initial performance test operated at steady state conditions |
| | | 1.4 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
An Oxidation Catalyst on a natural gas boiler has a potential control efficiency of 50-90% or higher for CO emissions. Good combustion and operation practices produce varied emission reductions. An RBLC review shows that an oxidation catalyst is commonly used to achieve the BACT limit EKPC proposes. Both controls are technically feasible. Oxidation Catalyst and GCOP are selected as BACT for this unit.

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 and 24 | GCOP | 0.082 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 3.3 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion CO controls. OxCat is therefore deemed technically infeasible. GCOP is selected as BACT for these units.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | GCOP | 0.082 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and Good Combustion and Operations Practices (GCOP).

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion CO controls. OxCat is therefore deemed technically infeasible. GCOP is selected as BACT for these units.

**EU 21 CCGT Emergency Generator Engine**
**EU 22 CCGT Emergency Fire Pump Engine**

**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Combustion Design Controls and GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 21 & 22 | Certified Engine & GCOP | 2.6 g/HP-hr | N/A | Purchasing a certified engine |

**Technologies:**
The following technologies were reviewed for the above source: Diesel Oxidation Catalyst (DOC), Combustion Design Controls, and GCOP

**Analysis**:
While a Diesel Oxidation Catalyst is technically feasible for non-emergency engines, DOC is not considered technically feasible for emergency engines. Equipment operations will be limited to emergency events and required readiness testing. Maintenance checks and readiness testing requires the engine to be turned on for a short period of time, typically one hour. The emission rate varies during startup and shutdown. DOC requires time for the exhaust to reach the required operating temperature and there isn't adequate run-time for emergency engines to make the control feasible. Therefore, purchasing an

engine certified to meet the requirements of 40 CFR Part 60 Subpart IIII GCOP are selected as BACT for this unit.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities at all times when combusting 100% natural gas or co-firing natural gas with coal, excluding periods of startup and shutdown:

| Emission Point | BACT | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 02 | GCOP | 0.12 lb/MMBtu | 3-hour average | Performance Test (US EPA Reference Method 10) |
| | | 1,278 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Thermal oxidation, OxCat, and GCOP.

**Analysis**:
Thermal oxidation requires temperatures of about 1,500 °F. The system would have to be installed prior to the existing flue gas desulfurization (FGD) to reach the appropriate temperature without the need to reheat the gas stream. This would result in increased emissions of other pollutants, such as $H_2SO_4$. If installed after the FGD, the gas stream would require reheating, requiring additional fuel combustion that would result in increased emissions.

Oxidation catalyst technology requires the gas stream to be in an ideal temperature range of 600° to 800° F, and control efficiency increases with temperature within this range. Additionally, particulate-laden streams will coat and de-activate the catalyst, thus the system would need to be installed after the existing baghouses which would require reheating the gas stream to achieve the appropriate temperature range. While the gas stream is in the appropriate temperature range prior to the SCR, the catalyst would be susceptible to poisoning from metallic and sulfur compounds in the stream at that point and plugging from particulate matter, as this is prior to the baghouse.

Since the technologies to control VOC are either technically or environmentally infeasible, GCOP is chosen as BACT for VOC control.

**EU 17 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for CO. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for CO | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | GCOP | 0.082 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 4.0 tpy | N/A | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion CO controls. OxCat is therefore deemed technically infeasible. GCOP is selected as BACT for these units.

C. <u>**BACT Analysis for VOC**</u>
**Technologies Reviewed:**
*<u>Oxidation Catalyst (OxCat) Technology</u>*
OxCat technology consists of a catalyst bed comprised of precious metals that promotes the oxidation of CO to $CO_2$ without the use of additional reaction accelerants (such as ammonia or urea used in an SCR for $NO_X$ control). The basic chemical reactions in the exhaust stream from an oxidation catalyst are as follows:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2$$

$$C_nH_m + \left(n + \frac{m}{4}\right)O_2 \rightarrow n\,CO_2 + \left(\frac{m}{2}\right)H_2O$$

$$C_nH_mO + \left(n + \frac{m}{4} - 0.5\right)O_2 \rightarrow n\,CO_2 + \left(\frac{m}{2}\right)H_2O$$

$$2H_2 + O_2 \rightarrow 2H_2O$$

Different catalyst materials can be used depending on the gas stream, with precious metals such as platinum, palladium, or rhodium being most common. Destruction efficiencies for VOC are typically 90% or more, depending on the catalyst used, operating temperature, and the presence of other pollutants.

*EMx™/SCONOx™/METEOR™*

EMx™, SCONOx™, and METEOR™ are multi-pollutant post combustion control technologies that use a coated oxidation catalyst to control VOC emissions without a reagent such as $NH_3$. The EMx™/SCONOx™ catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. All three systems use an oxidation catalyst that provides an equivalent level of control for VOC emissions to other oxidation catalysts.

*Good Combustion and Operations Practices (GCOP) Plan*

Good combustion and operations practices are operating practices and principles that allow the equipment to operate as efficiently as possible. It includes equipment design and operation consistent with good combustion practices to minimize incomplete combustion. Modern turbine control systems implement good combustion practices by using computer-based systems to adjust operating parameters automatically, ensuring complete combustion to minimize VOC emissions.

*Diesel Oxidation Catalyst (DOC)*

A Diesel Oxidation Catalyst (DOC) unit is a “flow through” control device for stationary diesel engines. The DOC contains a honeycomb-like structure or substrate with a large surface area. The structure is coated with an active catalyst layer that reduces CO and VOC emissions. The catalyst enables CO, gaseous hydrocarbons, and liquid hydrocarbon particles (unburned fuel and oil) in the exhaust to oxidize into $CO_2$ and $H_2O$. The CO and VOC reduction varies depending on the catalyst formulations in the DOC. DOC control efficiency can be up to 90% for CO and VOC.

*Combustion Design Controls*

Combustion Design Controls is the general term used to describe the process of specifying, purchasing, operating, and maintaining efficient combustion units for the purposes of emissions compliance. A common compliance requirement is to purchase a certified engine that meets the EPA’s emissions criteria for emergency or non-emergency engines. Conditions for other types of units may include purchasing efficient units and ensuring efficient operating scenarios for the units.

*Low-leaking components or Component type/design*

Component type/design or low-leaking components is a piping design method where the facility selects low leak piping components such as flanges, valves, compressors, and pipe fittings to minimize emissions from piping systems.

*Leak Detection and Repair (LDAR)*

LDAR programs identify leaking components such as pumps, valves, compressors, pipe fittings, and sampling connections in a piping system. LDAR is a work practice that is used to identify leaking equipment so emissions can be reduced through a regular repair or replacement schedule. LDAR inspections typically look for emission readings at 500 ppm above the background value and are usually implemented on a quarterly basis.

*Audio/Visual/Olfactory Detection (AVO)*
AVO inspections detect leaks through visual scanning for signs of leaks, listening for unusual sounds, and smelling any natural gas or diesel odors. An AVO inspection program may include the addition of mercaptans to the piping system which can be detected by odor at a level under 500 ppm. AVO monitoring is performed regularly by facility personnel during normal activities.

*Thermal Oxidation*
A thermal oxidizer reduces the amount of VOC present in an exhaust stream by supplying sufficient combustion air and supplemental fuel at a suitable temperature to all for oxidation of VOC.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Oxidation Catalyst and GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|---|
| 18 & 19 | When combusting Natural Gas | OxCat and GCOP | 1.0 ppmvd at 15% $O_2$, excluding SU/SD | 3-hour average | Initial performance test |
| | When combusting ULSFO | OxCat and GCOP | 1.0 ppmvd at 15% $O_2$, excluding SU/SD | 3-hour average | Initial performance test |
| | Both Fuels | | 250 tpy, including SU/SD | 12-month rolling average | Recordkeeping |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst, EMx$^{TM}$/SCONOx$^{TM}$/METEOR$^{TM}$, and GCOP.

**Analysis**:
EMx$^{TM}$/SCONOx$^{TM}$/METEOR$^{TM}$ technologies have not been used commercially for large combustion turbines due to engineering challenges and are considered technically infeasible. Oxidation Catalysts (OxCat) typically operate within a temperature range of 600°F to 800°F. A combined cycle turbine with a heat recovery steam generator (HRSG) lowers the exhaust gas temperature into the oxidation catalyst's operating range. While the fuel used impacts the effectiveness of an OxCat, a properly designed OxCat is capable of operating during both natural gas and fuel oil operation. Modern turbine control systems can implement good combustion practices by using computer-based systems to adjust operating parameters automatically.

 

The post-combustion controls take longer to achieve the rated destruction efficiency than the turbine takes to reach steady state, so when the system is starting up and shutting down, emissions of VOC are considered uncontrolled.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Oxidation Catalyst and GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | OxCat and GCOP | 0.0054 lb/MMBtu | 3-hour average | Combustion of pipeline quality natural gas |
| | | 2.3 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
An Oxidation Catalyst on a natural gas boiler has a potential control efficiency of 50-60% for VOC emissions. GCOP produces varied emission reductions. An RBLC review shows that an oxidation catalyst was used previously at other facilities to achieve the BACT limit EKPC proposes. Therefore, both controls are technically feasible.

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 & 24 | GCOP | 0.005 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 0.2 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion VOC controls. OxCat is therefore deemed technically infeasible. GCOP is selected as BACT for these units.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | GCOP | 0.005 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion VOC controls. OxCat is therefore deemed technically infeasible. GCOP is selected as BACT for these units.

**EU 21 CCGT Emergency Generator Engine**
**EU 22 CCGT Emergency Fire Pump Engine**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Combustion Design Controls and GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $NO_X$ + VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 21 | GCOP | 4.8 g/HP-hr | N/A | Purchasing a certified engine |
| 22 | | 3.0 g/HP-hr | | |

**Technologies:**
The following technologies were reviewed for the above source: Diesel Oxidation Catalyst (DOC), Combustion Design Controls, and GCOP.

**Analysis**:
While a Diesel Oxidation Catalyst is technically feasible for non-emergency engines, DOC is not considered technically feasible for emergency engines. Equipment operations will be limited to emergency events and required readiness testing. Maintenance checks and readiness testing requires the engine to be turned for a short period of time, typically one hour. The emission rate varies during startup and shutdown. DOC requires time for the exhaust to reach the required operating temperature and there isn't adequate run-time for emergency engines to make the control feasible. Therefore, purchasing an engine

 

certified to meet the requirements of 40 CFR Part 60 Subpart IIII GCOP are selected as BACT for this unit.

**EUs 26A, 26B, 27 & 28 External Fuel Oil Storage Tanks**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of a submerged fill pipe and overfill/spill protection in each tank constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 26A, 26B, 27, & 28 | Submerged Fill Pipe & Overfill/Spill Protection | N/A | N/A | Maintain tanks in good operating condition. Install and operate submerged fill pipe. |

**Technologies:**
The following technologies were reviewed for the above source: Submerged fill pipe and overflow/spill protection

**Analysis**:
Due to the small amount of VOC potentially emitted from these units, a "top down" BACT analysis was not completed for these units. Due to the low vapor pressure of ULSFO, no control techniques have been applied for tanks storing fuel oil. The use of a submerged fill pipe and overfill/spill protection are selected as BACT for these units.

**EU 33 Natural Gas Fugitive Piping Components**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Component type/design using low leak components and AVO leak detection plan constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 33 | Component type/design and AVO | N/A | N/A | Monthly AVO inspections; Recordkeeping of AVO inspections |

**Technologies:**
The following technologies were reviewed for the above source: Component type/design, Leak Detection and Repair (LDAR), and Audio/Visual/Olfactory Detection (AVO).

**Analysis**:
While an LDAR program is technically feasible for controlling VOC emissions from piping components, EKPC cites the small number of piping components and low emission rates as a basis for claiming LDAR is economically infeasible. AVO inspections

provide a simpler method of leak detection through visual scanning, listening for unusual sounds, and smelling for NG odors. AVO will allow plant personnel to monitor for leaks much more frequently than LDAR. Component type/design and implementation of an AVO leak detection plan is selected as BACT for this unit.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of good combustion and operations practices constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities when combusting 100% natural gas or co-firing natural gas with coal, excluding periods of startup and shutdown:

| Emission Point | BACTs | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 02 | GCOP | 0.0055 lb/MMBtu | 3-hour average | EPA Reference Method 18, 25 or 25A |
| | | 58 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: thermal oxidation, OxCat, and GCOP.

**Analysis**:
Thermal oxidation requires temperatures of about 1,500 °F. To reach the appropriate temperature without the need to reheat the gas stream, the system would have to be installed prior to the existing flue gas desulfurization device (FGD). This would result in increased emissions of $H_2SO_4$ as the sulfur compounds in the stream would be oxidized along with CO and VOC. If installed after the FGD, the gas stream would require reheating, requiring additional fuel combustion that would result in increased emissions.

Oxidation catalyst technology requires the gas stream to be in an ideal temperature range of 600° to 800° F, with control efficiency increasing with temperature within this range. Additionally, particulate-laden streams will coat and de-activate the catalyst, thus the system would need to be installed after the existing baghouses which would require reheating the gas stream to achieve the appropriate temperature range. While the gas stream is in the appropriate temperature range prior to the SCR, the catalyst would be susceptible to poisoning from metallic and sulfur compounds in the stream at that point and plugging from particulate matter, as this is prior to the baghouse.

Since the technologies to control VOC are either technically or environmentally infeasible, GCOP is chosen as BACT for VOC control.

**EU 17 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for VOC. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for VOC | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | GCOP | 0.005 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations |
| | | 0.3 tpy | 12-month rolling average | |

**Technologies:**
The following technologies were reviewed for the above source: Oxidation Catalyst and GCOP.

**Analysis**:
A review of the RBLC database found no similarly sized natural gas fired heaters using oxidation catalyst as post combustion VOC controls. OxCat is therefore deemed technically infeasible, and GCOP is selected as BACT for these units.

**D. <u>BACT Analysis for PM/$PM_{10}$/$PM_{2.5}$</u>**
**Technologies Reviewed:**
*Multicyclone (Cyclone)*
A cyclone is a centrifugal collector that uses inertia to remove particles from an exhaust stream. Filterable PM is propelled toward the cyclone walls by centrifugal force, but this movement is opposed by the fluid drag force of the gas travelling out of the cyclone. For larger particles, the centrifugal force exceeds the drag force, and the particles are collected. Smaller particles leave the cyclone with the exiting gas.

Multiple cyclones (multicyclones) can be operated in parallel to accommodate higher inlet flowrates compared to a single cyclone unit. The allowable inlet gas temperature for a cyclone can be as high as 540°C (1,000°F). High efficiency cyclones offer a control efficiency of 30-90% for $PM_{10}$ and 20-70% for $PM_{2.5}$. A multicyclone setup results in a higher PM control efficiency of 80-95% for $PM_5$. Cyclones are generally used as pre-cleaners for final control devices such as fabric filters/baghouses or ESPs.

*Wet Scrubber*
Wet scrubber or wet suppression involves the use of water or suitable chemicals to prevent PM from becoming airborne or remove PM from exhaust gases. Inlet gas temperatures for wet scrubbers typically range from 4-400°C (40-750 F) with typical gas flowrates for single-throat scrubbers ranging from 500-100,000 scfm. A wet scrubber can generally achieve approximately 80-99% control efficiency for filterable PM. Wet scrubber control efficiencies are not as high as a baghouse or ESP.

*Electrostatic Precipitator (ESP)*
ESP removes particulate matter from a gas stream by using electrical energy to charge particles that are then attracted to collector plates. Ideally, particles will have moderate electric resistivity. While ESPs can be designed for large gas volumes (wet or dry) and a wide temperature range, an ESP is not flexible to changes in operating conditions beyond the original design parameters. The control efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. An ESP generally achieves 99-99.99% control efficiency for filterable PM emissions.

Dry ESP typically operate at a temperature above the dew point for most condensable PM, so as to prevent issues associated with corrosion due to condensable acid gases. Wet ESP typically operate at saturated flue gas conditions, below the dew point of most condensable PM.

*Fabric Filter / Baghouse*
A fabric filter or baghouse consists of long, typically vertically suspended cylindrical fabric filters that remove particulate matter from the exhaust gas stream. The particles are deposited on the fabric as the gas stream passes through the baghouse filter media. Under proper operating conditions, a baghouse can generally achieve approximately 99-99.99% control efficiency for filterable PM emissions.

*Inlet Air Filters*
Inlet air filters reduce the amount of solid PM entering the combustion chamber. The filters capture solids entrained in the combustion air before they enter the combustion chamber.

*Low Sulfur Fuels*
Sulfur contained in the fuel reacts in the gas stream to form solid sulfur compounds and as a result, increases PM in the exhaust gases. Natural gas and ultra low sulfur diesel fuels have inherently low sulfur contents.

*Good Combustion and Operations Practices (GCOP) Plan*
Good combustion operation practices are operating practices and principles that allow the equipment to operate as efficiently as possible. $PM/PM_{10}/PM_{2.5}$ emissions mainly result from incomplete combustion. GCOP minimizes incomplete combustion by controlling parameters such as fuel feed rates, air/fuel ratios and periodic tuning.

*Combustion Design Controls*
Combustion Design Controls is the general term used to describe the process of specifying, purchasing, operating, and maintaining efficient combustion units for the purposes of emissions compliance. A common compliance requirement is to purchase a certified engine that meets the EPA's emissions criteria for emergency or non-emergency engines. Conditions for other types of units may include purchasing efficient units and ensuring efficient operating scenarios for the units.

*Catalyzed Diesel Particulate Filter (CDPF)*
CDPF is used to remove PM from diesel and gasoline engine exhausts. A catalyst is applied onto filter media to promote a chemical reaction between components of the gas

and the soot collected in the filter. The filter traps particles via filtration and eliminates them through oxidation to regenerate the filter.

*Drift Eliminators*
Drift eliminators, also known as mist eliminators, are add-on controls for cooling towers designed to minimize the escape of water droplets into the atmosphere. As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower. These emissions are known as "drift loss". There are dissolved solids in the water droplets that become airborne PM emissions when the water evaporates. Drift eliminators reduce drift formation, which reduces $PM/PM_{10}/PM_{2.5}$ that's entrained in the water droplets.

*Dry Flue Gas Desulfurization (FGD) with Baghouse/Fabric Filter*
Dry FGD involves the injection of alkaline reagents, most commonly sodium bisulfite, sodium carbonate, and hydrated lime. The reagents and the acid gases in the flue gas stream react with or absorb condensable PM and other acid gases to produce a solid product that can be captured by controls designed for filterable PM, such as a baghouse or fabric filter.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Inlet Air Filters, Low Sulfur Fuels, and GCOP constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | | BACT Limit for $PM/PM_{10}/PM_{2.5}$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|---|
| 18 & 19 | Natural Gas | Inlet Air Filters, Low Sulfur Fuel, & GCOP | 0.006 lb/MMBtu | 3-hour average | Performance testing |
| | ULSFO | Inlet Air Filters, Low Sulfur Fuel, & GCOP | 0.014 lb/MMBtu | 3-hour average | Performance testing |
| | Both Fuels | | 84.3 tpy | 12-month rolling total | Recordkeeping |

**Technologies:**
The following technologies were reviewed for the above source: Multicyclone (Cyclone), Wet Scrubber, ESP, Baghouse, Inlet Air Filters, Low Sulfur Fuel, and GCOP.

**Analysis**:
Multicyclone (Cyclone), Wet Scrubber, Electrostatic Precipitator, and Baghouse have not been used commercially for large combustion turbines and are considered

 

technically infeasible. Inlet Air Filters, Low Sulfur Fuel, and GCOP are all technically feasible for combustion turbines. The underlying design of the combustion turbines uses low sulfur fuels, inlet filters, and good combustion operating practices to mitigate $PM/PM_{10}/PM_{2.5}$ emissions from natural gas and fuel oil firing. Inlet air filters, low sulfur fuels, and good combustion operating practices have been selected as BACT for these units. The Division requires current, valid gas analysis records from the vendor to be maintained on site.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and pipeline quality natural gas constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for PM (filterable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | Combustion of pipeline quality natural gas and GCOP | 0.0019 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 1.4 tpy | 12-month rolling total | |

| Emission Point | BACTs | BACT Limit for $PM_{10}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 1.4 tpy | 12-month rolling total | |

| Emission Point | BACTs | BACT Limit for $PM_{2.5}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 1.4 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: GCOP and Low Sulfur Fuel.

**Analysis**:
GCOP and using low sulfur fuels are both technically feasible controls for this unit. Combusting pipeline quality natural gas GCOP are selected as BACT for this unit.

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and using pipeline quality natural gas constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for PM (filterable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 | Combustion of pipeline quality natural gas and GCOP | 0.0019 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |
| 24 | Combustion of pipeline quality natural gas and GCOP | 0.0019 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |

| Emission Point | BACTs | BACT Limit for $PM_{10}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |
| 24 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |

| Emission Point | BACTs | BACT Limit for $PM_{2.5}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |
| 24 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.1 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: GCOP and Low Sulfur Fuel

**Analysis**:
Implementing GCOP and using low sulfur fuels are both technically feasible controls for these units. Combusting pipeline quality natural gas and GCOP are selected as BACT for these units.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and using pipeline quality natural gas constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $PM/PM_{10}/PM_{2.5}$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | Combustion of pipeline quality natural gas and GCOP | 0.003 lb/MMBtu | N/A | Natural gas sulfur content 0.5 gr/100scf or less & GCOP |

**Technologies:**
The following technologies were reviewed for the above source: GCOP and Low Sulfur Fuel

**Analysis**:
Implementing GCOP and using low sulfur fuels are both technically feasible controls for this unit. Combusting pipeline quality natural gas and GCOP are selected as BACT for these units.

**EU 21 Diesel-Fired Emergency Generator Engine**
**EU 22 Diesel-Fired Fire Pump Engine**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP, Combustion Design Controls, and burning ultra low sulfur diesel fuel constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $PM/PM_{10}/PM_{2.5}$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 21 & 22 | Certified Engine, Combusting ULSFO, GCOP | 0.15 g/HP-hr | N/A | Purchasing a certified engine |

**Technologies:**
The following technologies were reviewed for the above source: Catalyzed Diesel Particulate Filter (CDPF), GCOP, and Low Sulfur Fuels.

**Analysis**:
The EPA has determined during the development of NSPS Subpart IIII that add-on controls are not cost effective for emergency engines. The CDPF is considered economically infeasible. While a Catalyzed Diesel Particulate Filter (CDPF) is technically feasible for non-emergency engines, CDPF is not considered technically feasible for emergency engines. Equipment operations will be limited to emergency events and required readiness testing. Maintenance checks and readiness testing requires the engine to be turned for a short period of time, typically one hour. The emission rate varies during startup and shutdown. DOC requires time for the exhaust to reach the required operating temperature and there isn't adequate run-time for emergency engines to make the control feasible. Therefore, good combustion operating practices (GCOP) and combusting ultra-low sulfur diesel fuel (ULSFO) are selected as BACT for this unit.

**EU 25 CCGT 9-Cell Mechanical Draft Cooling Tower**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Drift Eliminators constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for PM | BACT Limit for $PM_{10}$ | BACT Limit for $PM_{2.5}$ | Compliance Demonstration |
|---|---|---|---|---|---|
| 25 | Drift Eliminators | 1.04 lb/hr | 0.13 lb/hr | 0.0013 lb/hr | Monitor & maintain records of water flow total dissolved solids |
| | | 4.54 tpy | 0.59 tpy | 0.0055 tpy | |

**Technologies:**
The following technologies were reviewed for the above source: Drift Eliminators

**Analysis**:
PM emissions from cooling towers are a function of water recirculation rate (tower flow capacity), drift loss, and the concentration of total dissolved solids (TDS) in the cooling tower recirculating water. The planned TDS concentration is 2500 ppm. Minimizing TDS and advanced / high efficiency drift eliminators are two ways cooling tower PM emissions can be alleviated. Operating and maintaining records of high efficiency Drift Eliminators is selected as BACT for this unit.

**EU 32 CCGT Haul Roads**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of a Dust Control Plan constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $PM/PM_{10}/PM_{2.5}$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 32 | Dust Control Plan | N/A | N/A | Recordkeeping for control measures taken |

**Technologies:**
The following technologies were reviewed for the above source: Dust Control Plan.

**Analysis**:
A dust control plan for fugitive emissions from roadways includes surface improvements (pavement), speed limit signage, watering (good work practice), and/or other control methods (dust suppression systems, good housekeeping practices, etc.) as needed. A Dust Control Plan is selected as BACT for this unit.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of dry FGD with pulse jet fabric filter and GCOP constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities at all times when combusting 100% natural gas or a combination of natural gas and coal, excluding periods of startup and shutdown:

<table>
<tr><th>Emission Point</th><th>BACTs</th><th>BACT Limit for PM/PM$_{10}$/PM$_{2.5}$</th><th>Averaging Period</th><th>Compliance Demonstration</th></tr>
<tr><td rowspan="2">02</td><td rowspan="2">Dry FGD; PJFF; GCOP</td><td>0.030 lb/MMBtu</td><td>3-hour</td><td rowspan="2">US EPA Reference Method 5 (filterable), MATS-modified EPA Method 5 (filterable), or EPA Reference Methods 201 (filterable) and Method 202 (condensable)</td></tr>
<tr><td>310 tpy</td><td>12-month rolling total</td></tr>
</table>

**Technologies:**
The following technologies were reviewed for the above source: Dry FGD with Baghouse/Fabric Filter, ESP (dry or wet), Wet scrubber, Cyclone/multicyclone, GCOP

**Analysis**:
As unit 2 will operate under a variety of conditions, with the ability to combust 100% coal, 100% natural gas, or a combination of the two, and ESP systems are not flexible to changes in operating conditions, either a dry or wet ESP would be technically infeasible for this unit. Considering the rest of the controls, dry FGD with a bag house, wet scrubber, and cyclone/multicyclone, dry FGD has the highest potential control efficiency. The unit is already equipped with an FGD system, pulse jet fabric filter, and GCOP which will comprise BACT for the unit.

## EUs 17 Natural Gas-Fired Dewpoint Heaters

**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and using pipeline quality natural gas constitutes BACT for PM/PM$_{10}$/PM$_{2.5}$. The following BACT standards apply to each of the affected facilities:

<table>
<tr><th>Emission Point</th><th>BACTs</th><th>BACT Limit for PM (filterable)</th><th>Averaging Period</th><th>Compliance Demonstration</th></tr>
<tr><td rowspan="4">17</td><td rowspan="4">Combustion of pipeline quality natural gas and GCOP</td><td>0.0019 lb/MMBtu</td><td>3-hour block average</td><td rowspan="4">Combustion of pipeline quality natural gas and GCOP</td></tr>
<tr><td>0.2 tpy</td><td>12-month rolling total</td></tr>
<tr><td>0.1 tpy</td><td>12-month rolling total</td></tr>
<tr><td>0.1 tpy</td><td>12-month rolling total</td></tr>
</table>

| Emission Point | BACTs | BACT Limit for $PM_{10}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.2 tpy | 12-month rolling total | |
| | | 0.1 tpy | 12-month rolling total | |

| Emission Point | BACTs | BACT Limit for $PM_{2.5}$ (filterable + condensable) | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | Combustion of pipeline quality natural gas and GCOP | 0.0034 lb/MMBtu | 3-hour block average | Combustion of pipeline quality natural gas and GCOP |
| | | 0.2 tpy | 12-month rolling total | |
| | | 0.1 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: GCOP and Low Sulfur Fuel

**Analysis**:
Implementing GCOP and using low sulfur fuels are both technically feasible controls for this unit. Combusting pipeline quality natural gas and GCOP selected as BACT for these units.

**EU 35 Coal Storage and Handling Operations for Coal Stockpile #2**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of a Dust Control Plan constitutes BACT for $PM/PM_{10}/PM_{2.5}$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $PM/PM_{10}/PM_{2.5}$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 35 | Dust Control Plan | N/A | N/A | Recordkeeping for control measures taken |

**Technologies:**
The following technologies were reviewed for the above source: Dust Control Plan.

**Analysis**:
A dust control plan for fugitive emissions from roadways and stockpiles includes surface improvements (pavement), speed limit signage, watering (good work practice), and/or other control methods (dust suppression systems, good housekeeping practices, etc.) as needed. A Dust Control Plan is selected as BACT for this unit.

**E. BACT Analysis for $H_2SO_4$**

**Technologies Reviewed:**

*Flue Gas Desulfurization Scrubber (FGD Scrubber) & PM Control*
FGD scrubbers are control devices that utilize absorption and reaction using an alkaline reagent to produce a solid compound. The technology is commonly used on high sulfur fuel combustion units, such as coal- and oil-fired EGUs. The reaction of $SO_3$ with the alkaline reagent used in the FGD will form sulfites and sulfate salts, instead of $H_2SO_4$. Wet FGD scrubbers typically utilize sodium, calcium, or dual-alkali reagents using packed or spray towers, and generate wastewater and wet sludge streams that require treatment/disposal. For the purpose of $H_2SO_4$ control, a wet FGD would require the use of a wet ESP to remove the salts downstream. Dry FGD systems involve the injection of hydrated lime and an atomized alkaline slurry into the exhaust stream. $SO_3$ interacts with the slurry forming liquid sulfite/sulfate salts that are dried by the heat of the exhaust stream and subsequently removed from the stream by PM controls. The existing CDS system on unit 2 is considered a dry FGD system for the purposes of this analysis.

*Dry Sorbent Injection (DSI)*
Dry Sorbent Injection injects selected sorbents in the flue gas to control pollutants. DSI is primarily used on coal-fired boilers to remove $SO_2$ and HCL prior to exhaust.

*Low Sulfur Fuels*
Sulfur contained in the fuel reacts in the gas stream to form solid sulfur compounds including $SO_2$, $SO_3$, and $H_2SO_4$ which are suspended in the exhaust gases and enter the atmosphere. Natural gas and ultra low sulfur diesel fuels have inherently low sulfur contents.

*Good Combustion Operation Practices (GCOP Plan)*
Good combustion operation practices are operating practices and principles that allow the equipment to operate as efficiently as possible. $H_2SO_4$ emissions result from the reaction of $SO_3$ with water. $SO_2$ emissions are oxidized to form $SO_3$ which reacts with water to produce $H_2SO_4$. $H_2SO_4$ emissions primarily depend on the sulfur content of the fuel.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low Sulfur Fuels and GCOP constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|---|
| 18 & 19 | When combusting Natural Gas | Low Sulfur Fuel & GCOP | 0.5gr/100scf fuel sulfur content | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |
| | When combusting ULSFO | Low Sulfur Fuel & GCOP | Fuel sulfur content ≤ 15 ppm | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |

**Technologies:**
The following technologies were reviewed for the above source: Flue Gas Desulfurization (FGD Scrubber), Dry Sorbent Injection (DSI), Low Sulfur Fuel, GCOP.

**Analysis**:
Flue Gas Desulfurization (FGD Scrubber) and Dry Sorbent Injection (DSI) have not been used commercially for large combustion turbines and are considered technically infeasible. Low Sulfur Fuel and GCOP are technically feasible for combustion turbines. The underlying design of the combustion turbines uses low sulfur fuels, inlet filters, and good combustion operating practices during natural gas and fuel oil firing. Low sulfur fuels and good combustion operating practices have been selected as BACT for these units.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and Low Sulfur Fuels constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 20 | Combustion of pipeline quality natural gas, GCOP | 0.5 gr/100scf fuel sulfur content | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |

**Technologies:**
The following technologies were reviewed for the above source: Flue Gas Desulfurization (FGD Scrubber), Dry Sorbent Injection (DSI), GCOP, and Low Sulfur Fuel.

**Analysis**:
Flue Gas Desulfurization (FGD Scrubber) and Dry Sorbent Injection (DSI) have not been used commercially for large auxiliary boilers and are considered technically infeasible. Low Sulfur Fuel and Good Combustion Operating Practices (GCOP) are technically feasible for boilers. Low sulfur fuel and GCOP are selected as BACT for this unit.

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and Low Sulfur Fuels constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 | Combustion of pipeline quality natural gas, GCOP | 0.5 gr/100scf fuel sulfur content | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |
| 24 | | | | |

**Technologies:**
The following technologies were reviewed for the above source: Low Sulfur Fuel and GCOP.

**Analysis**:
A review of the RBLC database found no add-on control equipment for reducing $H_2SO_4$ emissions from small natural gas combustion heaters. Utilizing low sulfur fuel and GCOP are technically feasible and are selected as BACT for this unit.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and Low Sulfur Fuel constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | Combustion of pipeline quality natural gas, GCOP | 0.5 gr/100scf fuel sulfur content | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |

**Technologies:**
The following technologies were reviewed for the above source: Low Sulfur Fuel and GCOP.

**Analysis**:
A review of the RBLC database found no add-on control equipment for reducing $H_2SO_4$ emissions from small natural gas combustion heaters. Utilizing low sulfur fuel and GCOP are technically feasible and are selected as BACT for this unit.

**EU 34 $H_2SO_4$ Storage Tank**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of manufacturer's recommended procedures constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 34 | Manufacturer's recommended procedures | N/A | N/A | Recordkeeping of manufacturer's recommendations, tank inspections, and maintenance conducted |

**Technologies:**
The following technologies were reviewed for the above source: N/A

**Analysis**:
EKPC did not perform a full top-down BACT analysis, as there are no control options available given the low rate of anticipated potential emissions. The Division will not impose any additional monitoring for this unit. However, records shall be maintained of the manufacturer's recommendations, along with inspection and maintenance records for a period of at least 5 years following the inspection or maintenance activity.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of a dry FGD and fabric filter constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 02 | Dry FGD and PJFF | 0.005 lb/MMBtu | 3-hour block average | US EPA Reference Method 8, CTM-013 and CTM-013A |
| | | 57 tons | 12 month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: Dry FGD with fabric filter/baghouse, wet FGD with wet ESP, duct sorbent injection.

**Analysis**:
Due to the variability of operating conditions required to combust 100% coal, 100% natural gas, or a combination of the two, an ESP is not technically feasible. As this would be the appropriate way to control the PM produced as the formation of salts from a wet FGD system, wet FGD would also be considered infeasible. Dry FGD with a fabric filter is considered the most effective control technology for $H_2SO_4$. As the existing FGD and PJFF act as a dry FGD and fabric filter, these will comprise BACT for the unit.

**EU 17 Natural Gas-Fired Dewpoint Heater**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and Low Sulfur Fuels constitutes BACT for $H_2SO_4$. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for $H_2SO_4$ | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | Combustion of pipeline quality natural gas, GCOP | 0.5 gr/100scf fuel sulfur content | N/A | Vendor guarantee sulfur content 0.5 gr/100scf |

**Technologies:**
The following technologies were reviewed for the above source: Low Sulfur Fuel and GCOP.

**Analysis**:
A review of the RBLC database found no add-on control equipment for reducing $H_2SO_4$ emissions from small natural gas combustion heaters. Utilizing low sulfur fuel and GCOP are technically feasible and are selected as BACT for this unit.

**F. BACT Analysis for GHG**

**Technologies Reviewed:**

*Carbon Capture and Sequestration/Storage (CCS)*
Carbon Capture and Storage (CCS) is the process of capturing $CO_2$ emitted, drying and compressing the $CO_2$, and then transporting it to a long-term storage or conversion. CCS involves capturing $CO_2$ by absorption, adsorption, membranes, or cryogenic separation. The $CO_2$ is compressed to supercritical conditions and transported by pipeline or truck to long-term geologic storage or conversion. Currently, there are no EPA-approved injection sites in Kentucky for commercial-scale storage.

*Efficient CT Design and Operation*
Pollutant formation from CTs can be most cost-effectively minimized by efficient turbine design and GCOP. Operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Energy loss can be minimized by providing sufficient insulation outside the unit and around the associated duct work. Proper maintenance is important for efficient operation.

*Good Combustion and Operations Practices (GCOP) Plan*
Good combustion operating practices are operating practices and principles that allow the equipment to operate as efficiently as possible. Modern turbine control systems implement good combustion practices by using computer-based systems to adjust operating parameters automatically, ensuring complete combustion to minimize GHG emissions.

*Alternative Fuels / Biomass, Co-Firing Multiple Fuels, Co-Firing Low Carbon Fuel*
Alternative fuels, also commonly referred to as biomass fuels, include animal meal, waste wood products and sawdust, and sewage sludge. Biomass materials may also be

cultivated specifically for use as a fuel source such as wood, grasses, green algae, and other quick growing species. $CO_2$ emissions could potentially be reduced by switching to a different fuel or co-firing biomass with existing fuels.

Natural gas is the lowest carbon fuel generally available for power production. Use of natural gas is inherent in the proposed project and is the primary fuel. EKPC proposes the use of ULSFO when the availability of natural gas is limited.

The firing or co-firing of hydrogen with natural gas can further reduce GHG emissions and has been evaluated on large combustion units (such as turbines and utility boilers) but has not been employed in practice.

*Low Sulfur Fuels*
Sulfur contained in the fuel reacts in the gas stream to form solid sulfur compounds including $SO_2$, $SO_3$, and $H_2SO_4$ which are suspended in the exhaust gases and enter the atmosphere. Natural gas and ultra low sulfur diesel fuels have inherently low sulfur contents.

*Low-leaking components or Component type/design*
Component type/design or low-leaking components is a piping design method where the facility selects low leak piping components such as flanges, valves, compressors, and pipe fittings to minimize emissions from piping systems.

*Leak Detection and Repair (LDAR)*
LDAR programs identify leaking components such as pumps, valves, compressors, pipe fittings, and sampling connections in a piping system. LDAR is a work practice that is used to identify leaking equipment so emissions can be reduced through a regular repair or replacement schedule. LDAR inspections typically look for emission readings at 500 ppm above the background value and are usually implemented on a quarterly basis.

*Audio/Visual/Olfactory Detection (AVO)*
AVO inspections detect leaks through visual scanning for signs of leaks, listening for unusual sounds, and smelling any natural gas or diesel odors. An AVO inspection program may include the addition of mercaptans to the piping system which can be detected by odor at a level under 500 ppm. AVO monitoring is performed regularly by facility personnel during normal activities.

**EUs 18 & 19 Dual Fuel Combustion Turbine Units 3 & 4**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

<table>
<tr><th colspan="2">Emission Point</th><th>BACT</th><th>BACT Limit for GHG</th><th>Averaging Period</th><th>Compliance Demonstration</th></tr>
<tr><td rowspan="3">18 & 19</td><td>When combusting Natural Gas</td><td>GCOP</td><td>800 lb/MWh-gross</td><td>12-month average</td><td>$O_2$ or $CO_2$ CEMS</td></tr>
<tr><td>When combusting ULSFO</td><td>GCOP</td><td>1250 lb/MWh-gross</td><td>12-month average</td><td>$O_2$ or $CO_2$ CEMS</td></tr>
<tr><td colspan="2">Both Fuels</td><td>1,422,367</td><td>12-month rolling total</td><td>Recordkeeping</td></tr>
</table>

**Technologies:**
The following technologies were reviewed for the above source: CCS, Efficient CT Design and Operation, and GCOP.

**Analysis**:
CCS technology has been tested on a pilot scale but has not been used commercially for a large combined cycle combustion turbine. There are no existing or planned $CO_2$ pipelines within a reasonable distance from the EKPC Cooper site. There are no existing or planned commercially available chemical manufacturing facilities within a reasonable distance from the EKPC Cooper site capable of compressing the captured $CO_2$ to a supercritical state for transport. There are no existing or planned commercially available sequestration sites within a reasonable distance from the EKPC Cooper site. CCS is therefore deemed technologically infeasible.

GCOP is a technically feasible control option for reducing GHG emissions and is selected as BACT for these units.

**EU 20 Natural Gas-Fired Auxiliary Boiler**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low Carbon Fuel (pipeline quality natural gas) and GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

<table>
<tr><th>Emission Point</th><th>BACT</th><th>BACT Limit for GHG</th><th>Averaging Period</th><th>Compliance Demonstration</th></tr>
<tr><td rowspan="2">20</td><td rowspan="2">Pipeline quality natural gas and GCOP</td><td>117.1 lb/MMBtu $CO_2e$</td><td>N/A</td><td rowspan="2">Maintaining/operating in accordance with manufacturer’s recommendations and 40 CFR 63 Subpart DDDDD</td></tr>
<tr><td>49,147 tpy</td><td>12-month rolling total</td></tr>
</table>

**Technologies:**
The following technologies were reviewed for the above source: CCS, Alternative Fuels, Biomass, Co-Firing Multiple Fuels, Co-Firing Low Carbon Fuel, and GCOP.

**Analysis**:
CCS technology has been tested on a pilot scale but has not been used commercially and is considered technically infeasible for the same reasons outlined in the turbine BACT analysis. EKPC states that while it is possible to modify a natural gas boiler to accept biomass-derived gas, EKPC cannot guarantee a consistent supply of such fuels over the lifetime of the boiler. Alternate fuels / biomass and co-firing is therefore deemed technically infeasible. Additionally, combusting biomass fuels may affect compliance with BACT limits for other pollutants. Natural gas is already a low carbon fuel and has less $CO_2$ emissions than other available fuels. Low carbon fuel (pipeline quality natural gas) and GCOP have been selected as BACT for these units.

**EUs 23 & 24 Natural Gas-Fired Dewpoint Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low Carbon Fuel (pipeline quality natural gas) and GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACT | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 23 & 24 | Pipeline quality natural gas and GCOP | 117.1 lb/MMBtu CO2e | 3-hour block average | Maintaining/operating in accordance with manufacturer's recommendations |
| 23 & 24 | | 4,532 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: CCS, Alternative Fuels, Biomass, Co-Firing Multiple Fuels, Co-Firing Low Carbon Fuel, and GCOP.

**Analysis**:
CCS technology has been tested on a pilot scale but has not been used commercially and is considered technically infeasible for the same reasons outlined in the turbine BACT analysis. EKPC states that while it is possible to modify a natural gas boiler to accept biomass-derived gas, EKPC cannot guarantee a consistent supply of such fuels over the lifetime of the boiler. Alternate fuels / biomass and co-firing are therefore deemed technically infeasible. Natural gas is already a low carbon fuel and has less $CO_2$ emissions than other available fuels. Low carbon fuel (pipeline quality natural gas) and GCOP have been selected as BACT for these units.

**EU 29A Natural Gas-Fired HVAC Heaters**
**EU 29B and 29C Natural Gas-Fired HVAC Heaters**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low Carbon Fuel (pipeline quality natural gas) and GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 29A<br>29B<br>29C | Pipeline quality natural gas and GCOP | 117.1 lb/MMBtu $CO_2e$ | 3-hour average | Maintaining/operating in accordance with manufacturer's recommendations |
| 29A | | 6,001 tpy | 12-month rolling total | |
| 29B | | 123 tpy | 12-month rolling total | |
| 29C | | 554 | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: CCS, Alternative Fuels, Biomass, Co-Firing Multiple Fuels, Co-Firing Low Carbon Fuel, and GCOP.

**Analysis**:
CCS technology has been tested on a pilot scale but has not been used commercially and is considered technically infeasible for the same reasons outlined in the turbine BACT analysis. EKPC states that while it is possible to modify a natural gas boiler to accept biomass-derived gas, EKPC cannot guarantee a consistent supply of such fuels over the lifetime of the boiler. Alternate fuels / biomass and co-firing are therefore deemed technically infeasible. Natural gas is already a low carbon fuel and has less $CO_2$ emissions than other available fuels. Low carbon fuel (pipeline quality natural gas) and GCOP have been selected as BACT for these units.

**EU 21 CCGT Emergency Generator Engine**
**EU 22 CCGT Emergency Fire Pump Engine**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of GCOP and use of ultra-low sulfur diesel fuel constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 21 & 22 | Low Sulfur Fuel and GCOP | 163 lb/MMBtu $CO_2e$ | N/A | Purchase a certified engine and combusting ULSFO |

**Technologies:**
The following technologies were reviewed for the above source: Low Sulfur Fuel and GCOP.

**Analysis**:
The carbon content of fuels varies significantly across available fuels. Fuels with lower carbon intensity have lower GHG emissions. Ultra-low sulfur diesel fuel has been selected for low carbon intensity. Following the manufacturer's recommendations for maintenance and operation will optimize the engines' efficiency. Utilizing low sulfur fuel (ULSFO) and GCOP have been selected as BACT for this unit.

**EU 33 Natural Gas Fugitive Piping Components**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of AVO leak detection plan constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 33 | AVO | N/A | N/A | Monthly AVO inspections; Recordkeeping of AVO inspections |

**Technologies:**
The following technologies were reviewed for the above source: Component type/design, Leak Detection and Repair (LDAR), and Audio/Visual/Olfactory Detection (AVO).

**Analysis**:
While an LDAR program is technically feasible for controlling GHG emissions from piping components, EKPC cites the small number of piping components and low emission rates as a basis for claiming LDAR is economically infeasible. AVO inspections provide a simpler method of leak detection through visual scanning, listening for unusual sounds, and smelling for NG odors. AVO will allow plant personnel to monitor for leaks much more frequently than LDAR. Implementation of an AVO leak detection plan is selected as BACT for this unit.

**EU 30 3 Turbine Circuit Breakers**
**EU 31 12 Switchyard/Station Circuit Breakers**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low-leaking components and leak detection system and recordkeeping constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 30 & 31 | Component type/design and leak detection system | Maximum Leak Rate = 0.5% $SF_6$ | N/A | Recordkeeping of AVO inspections and leak detection system |

**Technologies:**
The following technologies were reviewed for the above source: Low-leaking components or Component type/design and Audio/Visual/Olfactory Detection (AVO)

**Analysis**:
Circuit breakers contain sulfur hexafluoride ($SF_6$) as an insulating material. Non-GHG circuit breaker insulating material is not yet commercially available for the size and scale of the project and is therefore deemed technically infeasible. Purchasing a low leak circuit breaker system design, a leak detection system, and recordkeeping associated with the leak detection system is selected as BACT for this unit.

**EU 02 Co-Fired Boiler (C2)**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of lower carbon fuel (natural gas co-firing) and GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 02 | Lower Carbon Fuel & GCOP | 2,074 lb/MWh-g of $CO_2$ | 12-month rolling average | Part 75 procedures and Recordkeeping (See **5. <u>Specific Recordkeeping Requirements</u>** r.) |
| | | 2,146,866 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: CCS, Low carbon fuels, efficient boiler operation and GCOP

**Analysis**:
While converting to the ability to combust natural gas is considered a lower carbon fuel than coal combustion, in order to meet the energy demands and support projected increased grid demands, the unit needs to maintain the ability to combust coal. Low carbon fuels are a potential control option, only to the extent that they do not interfere with the grid reliability and fuel flexibility of the project. There are not currently any EPA-approved CCS injection sites for long term commercial storage in the state nor $CO_2$ pipelines to transport the gas to an appropriate storage location; thus, CCS is not considered feasible.

**EU 17 Natural Gas-Fired Dewpoint Heater**
**Decision Summary:**
Consistent with the BACT evaluation conducted and submitted by EKPC, the Division determines the use of Low Carbon Fuel (pipeline quality natural gas) and GCOP constitutes BACT for GHG. The following BACT standards apply to each of the affected facilities:

| Emission Point | BACTs | BACT Limit for GHG | Averaging Period | Compliance Demonstration |
|---|---|---|---|---|
| 17 | Pipeline quality natural gas and GCOP | 117.1 lb/MMBtu CO2e | 3-hour block average | Maintaining/operating in accordance with manufacturer's recommendations |
| | | 5,783 tpy | 12-month rolling total | |

**Technologies:**
The following technologies were reviewed for the above source: CCS, Alternative Fuels, Biomass, Co-Firing Multiple Fuels, Co-Firing Low Carbon Fuel, and GCOP.

**Analysis**:
CCS technology has been tested on a pilot scale but has not been used commercially and is considered technically infeasible for the same reasons outlined in the turbine BACT analysis. EKPC states that while it is possible to modify a natural gas boiler to accept biomass-derived gas, EKPC cannot guarantee a consistent supply of such fuels over the lifetime of the boiler. Alternate fuels / biomass and co-firing is therefore deemed technically infeasible. Natural gas is already a low carbon fuel and has less $CO_2$ emissions than other available fuels. Low carbon fuel (pipeline quality natural gas) and GCOP have been selected as BACT for these units.

# IV. Air Quality Impact Analysis

## A. Screening Methodology

The incremental increases in ambient pollutant concentrations associated with the EKPC Cooper Station project have been estimated through the use of a dispersion model (AERMOD version 24142 released November 2024). The submitted demonstration adheres to applicable guidelines in the United States Environmental Protection Agency (U.S. EPA) *Guideline on Air Quality Models* (GAQM, 40 CFR 51 Appendix W, Revised March 21, 2017), U.S. EPA's *AERMOD Implementation Guide* (November 2024), U.S. EPA's *User Guide for the AMS/EPA Regulatory Model (AERMOD)*, and other applicable guidance. The submission follows the methodology presented in the Air Dispersion Modeling Protocol approved by KDAQ on June 11, 2025.

Model simulations for short-term and annual-averaged CO, $NO_2$, $PM_{10}$, and $PM_{2.5}$ emissions are performed with the AERMOD model using the 5-year meteorological database. The highest predicted impacts (H1H) were used as the design concentrations in the Significant Impact Level (SIL) analyses. The design concentrations for the NAAQS and PSD increment analyses used the NAAQS and PSD increment for each applicable pollutant and averaging time. Each pollutant was assessed against the SIL for NAAQS compliance: the maximum value over 5 years for each applicable time averaging period is compared to the appropriate SIL value.

**Significant Impact Levels (SILs)**

| Pollutant | Averaging Period | Modeled Concentration (µg/m$^3$) | Significant Impact Level (µg/m$^3$) | SIL Exceeded & Additional Modeling Required? | Significant Monitoring Concentrations (µg/m$^3$) | Significant Monitoring Concentration Exceeded? [1] |
|---|---|---|---|---|---|---|
| CO | 1-hour | 11,683 | 2000 | Yes | - | - |
| | 8-hour | 3,398 | 500 | Yes | 575 | Yes |
| $NO_2$ | 1-hour | 135 | 7.5 | Yes | - | - |
| | Annual | 2.6 | 1 | Yes | 14 | No |
| $PM_{10}$ | 24-hour | 33.3 | 5 | Yes | 10 | Yes |
| | Annual | 1.30 | 1 | Yes | - | - |
| $PM_{2.5}$ | 24-hour | 5.13 | 1.2 | Yes | 0 | Yes |
| | Annual | 0.39 | 0.13 | Yes | - | - |

**1:** The applicant may propose that the reviewing authority considers the use of existing monitoring data if appropriate justification is provided. The modeled impacts of 8-hour CO, 24-hour PM10, and 24-hour PM2.5 exceed their applicable SMCs (575 µg/m³, 10 µg/m3, and 0 µg/m3). A pre-construction monitoring waiver was submitted to the Division under separate cover in January 2025.

For $NO_2$ modeling, EKPC Cooper uses the Tier 3 methodology to produce compliant modeling results using the Plume Volume Molar Ratio Method (PVMRM) approach in the modeling analysis. EKPC Cooper uses published In Stack Ratio (ISR) data from the U.S. EPA, the Electric Power Research Institute (EPRI), and the San Joaquin Valley Air Pollution Control District (SJVAPCD), equipment-specific ISR data using equipment specific testing, and vendor guarantees.

| Unit | Fuel | ISR | Source |
|---|---|---|---|
| Unit 1 Boiler | Coal | 0.1 | EPA ISR Database (Max of Coal-Fired Boiler Data) |
| Unit 2 Boiler | Natural Gas | 0.1 | SJVAPCD for Natural Gas-Fired Boilers |
| Auxiliary Boiler<br>Dew Point Heaters<br>Building AHUs | Natural Gas | 0.1 | SJVAPCD for Natural Gas-Fired Boilers |
| Combined Cycle Turbines | Natural Gas<br>Fuel Oil | 0.5 | Default in-stack ratio for Tier 3 modeling per EPA $NO_2$ Clarification Memo (March 2011) |
| Emergency Generators | Diesel | 0.2 | SJVAPCD for Diesel Internal Combustion Engines |
| Nearby Sources[A] | Various | 0.2 | EPA $NO_2$ Clarification Memo (September 2014) |

**A:** As noted by U.S. EPA, a default ISR value of 0.2 is appropriate for sources greater than 1-3 km away.

## B. Background Concentrations

Representative background concentrations were added to the maximum predicted concentrations so that small sources that were not explicitly modeled are included in the NAAQS and KYAAQS assessment. Background concentrations are based on ambient monitoring data collected for the most recent three-year period available (2022 through 2024). This period is determined to be the most representative for use in the modeling analysis. Since all of the criteria pollutants are not monitored at one location, data from several monitoring locations are utilized.

**Representative Background Concentrations**

| Site ID | Monitoring Location | Data Collection Period | Pollutant | Averaging Period | Background Concentration (Design Value) | Basis of Design Value |
|---|---|---|---|---|---|---|
| 21-061-0501 | Bowling Green, KY | 2023-2024 | CO | 8-hour [A] | 685.7 μg/m$^3$ | 2nd high concentration over 2023-2024 period |
| | | | | 1-hour [A] | 800 μg/m$^3$ | |
| 47-009-0101 | Knoxville, TN | 2022-2024 | $NO_2$ | Annual [B] | 1.9 μg/m$^3$ | Highest value from 3-year period |
| | | | | 1-hour [B] | 9.4 μg/m$^3$ | 3-year average 98th percentile 1-hour average |
| 21-199-0003 | Somerset, KY | 2022-2024 | Ozone | 8-hour [C] | 59.0 ppb | 3-year average of the annual 4th highest daily max 8-hour concentration |
| 21-067-0012 | Lexington, KY | 2022-2024 | $PM_{10}$ | 24-hour | 34.0 μg/m$^3$ | 4th high 24-hour concentration over 3-year period |
| 21-199-0003 | Somerset, KY | 2022-2024 | $PM_{2.5}$ | Annual | 7.1 μg/m$^3$ | Average monitor value from 3-year period |
| | | | | 24-hour | 17.0 μg/m$^3$ | 3-year average 98th percentile 24-hour average |

**A:** The CO background concentration for the selected candidate monitoring station did not change from the 2022-2023 two-year period to the 2023-2024 two-year period [See *Revised Cooper Project Class II Modeling Report* Section 2.12.1, pages 25 and 26]
**B:** The $NO_2$ background concentration for the selected candidate monitoring station did not change from the 2021-2023 three-year period to the 2022-2024 three-year period [See *Revised Cooper Project Class II Modeling Report* Section 2.12.2, pages 26 and 27]
**C:** Hourly varying ozone background concentration was used as the input for Tier 3 $NO_2$ conversion option Plume Volume Molar Ratio Method (PVMRM).

## C. Secondary $PM_{2.5}$ Impact Assessment and Ozone Impact Assessment

$PM_{2.5}$ precursors ($NO_X$ and $SO_2$) can undergo photochemical reactions with ambient gases, such as $NH_3$ and VOC, resulting in the formation of secondary $PM_{2.5}$ downwind of a stationary industrial source, which is unaccounted for using AERMOD dispersion modeling. The GAQM recommends the use of Modeled Emission Rates for Precursors (MERPs) to evaluate the project's impact on secondary $PM_{2.5}$ levels in the surrounding airshed. EKPC Cooper uses the U.S. EPA's Barren County hypothetical source in the Tier-1 modeling analysis, as this source has similar terrain and surrounding land use to EKPC Cooper. The Barren County hypothetical source is generally within the same air shed as EKPC Cooper Station and has similar atmospheric chemistry and secondary pollutant formation processes.

**Secondary $PM_{2.5}$ NAAQS MERPs Analysis**

| Averaging Period | Precursor | Modeled Emissions from Hypothetical Source (tpy) | Modeled Impact from Hypothetical Source (µg/m$^3$) | Project Emissions Increase (tpy) | Secondary $PM_{2.5}$ Project Impact (µg/m$^3$) | SIL (µg/m$^3$) |
|---|---|---|---|---|---|---|
| 24-hour | $NO_X$ | 1,000 | 0.089 | 1,116.5 | 0.09877 | |
| | $SO_2$ | 500 | 0.129 | 38.9 | 0.01003 | |
| | | | | **Total** | **0.10891** | **1.2** |
| | | | | | | |
| Annual | $NO_X$ | 1,000 | 0.004 | 1,116.5 | 0.00446 | |
| | $SO_2$ | 500 | 0.004 | 38.9 | 0.00031 | |
| | | | | **Total** | **0.00476** | **0.13** |

The hypothetical source is a source located in Barren County, KY from EPA's MERPs View Qlik website. The hypothetical source emission rate represents the closest value available in MERPs View Qlik to the source-wide PTE for $NO_X$ and $SO_2$ for the project.

The ozone impact assessment requires selecting the nearest hypothetical source modeled by the U.S. EPA to Cooper Station. EKPC Cooper uses the U.S. EPA's Barren County hypothetical source in the Tier-1 modeling analysis, as this source has similar terrain and surrounding land use to EKPC Cooper. The Barren County hypothetical source is generally within the same air shed as EKPC Cooper Station and has similar atmospheric chemistry and secondary pollutant formation processes.

**Ozone SIL Analysis**

| Averaging Period | Precursor | Modeled Emissions from Hypothetical Source (tpy) | Modeled Impact from Hypothetical Source (ppb) | Project Emissions Increase (tpy) | Ozone Project Impact (ppb) | SIL (µg/m$^3$) |
|---|---|---|---|---|---|---|
| 24-hour | $NO_X$ | 1,000 | 5.026 | 1,116.5 | 5.61 | |
| | VOC | 500 | 0.060 | 557.3 | 0.07 | |
| | | | | **Total** | **5.68** | **1.0** |

The hypothetical source is located in Barren County, KY from EPA's MERPs View Qlik website using the procedure referenced in the Clarification on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, April 30, 2024. The hypothetical source emission rate represents the closest value available in the MERPs guidance to the post-project source-wide PTE for $NO_X$ and VOC for the expansion project.

The calculated MERPs concentrations are added to the background ozone concentration taken from the Pulaski County monitor (Site ID 21-199-0003), which demonstrates compliance with the ozone 8-hour NAAQS. The monitored background ozone concentration represents concentrations from both nearby and other (e.g., mobile and/or distant) sources. When added to the EKPC Cooper Project-specific ozone concentration increase, the combined impact represents a full cumulative assessment against the NAAQS.

**Ozone NAAQS Analysis**

| Averaging Period | Pollutant | Ozone Project Impact (ppb) | Ozone Background Concentration [A] (ppb) | Cumulative Ozone Impact (ppb) | NAAQS (ppb) |
|---|---|---|---|---|---|
| 8-hour | Ozone | 5.68 | 59 | **64.68** | **70** |

**A:** Three-year average for 2022-2024 of the annual 4$^{th}$ highest daily maximum 8-hour concentrations measured at the Somerset, KY monitor (Site ID 21-199-0003).

## D. Class II Modeling Results

The EKPC Cooper Project causes impacts above the $NO_2$ SIL for both the 1-hour and annual averaging periods. Further NAAQS and Class II Increment Analyses are required because these impacts are greater than the SILs.

**$NO_2$ SIL Modeling Analysis Results**

| Averaging Period | Year for Met. Data | SIL (µg/m³) | Significant Monitoring Concentration (µg/m³) | Maximum 1st High Impact (µg/m³) | UTM East (m) A | UTM North (m) A |
|---|---|---|---|---|---|---|
| 1-hour | 2020 | | | 132.0 | 715,350 | 4,099,943 |
| | 2021 | | | 131.7 | 715,350 | 4,099,943 |
| | 2022 | | | 135.0 | 715,350 | 4,099,943 |
| | 2023 | | | 131.4 | 715,350 | 4,099,943 |
| | 2024 | | | 132.9 | 715,350 | 4,099,943 |
| | **Max. of 5 years** | **7.5** | **N/A** | **135.0** | **715,350** | **4,099,943** |
| | | | | | | |
| Annual | 2020 | | | 2.4 | 714,456 | 4,097,764 |
| | 2021 | | | 2.6 | 714,456 | 4,097,764 |
| | 2022 | | | 2.4 | 714,456 | 4,097,764 |
| | 2023 | | | 2.2 | 714,456 | 4,097,764 |
| | 2024 | | | 2.5 | 714,456 | 4,097,764 |
| | **Max. of 5 years** | **1** | **14** | **2.6** | **714,456** | **4,097,764** |

**A:** UTM coordinates are in NAD83 Zone 16

The EKPC Cooper Project causes impacts above the $PM_{10}$ SIL for both the 24-hour and annual averaging periods. Further NAAQS and Class II Increment Analyses are required because these impacts are greater than the SILs.

**$PM_{10}$ SIL Modeling Analysis Results**

| Averaging Period | Year for Met. Data | SIL (µg/m³) | Significant Monitoring Concentration (µg/m³) | Maximum 1st High Impact (µg/m³) | UTM East (m) A | UTM North (m) A |
|---|---|---|---|---|---|---|
| 24-hour | 2020 | | | 24.1 | 714,438 | 4,097,770 |
| | 2021 | | | 33.3 | 714,456 | 4,097,764 |
| | 2022 | | | 28.3 | 714,456 | 4,097,764 |
| | 2023 | | | 29.3 | 714,456 | 4,097,764 |
| | 2024 | | | 22.7 | 714,456 | 4,097,764 |
| | **Max. of 5 years** | **5.0** | **10** | **33.3** | **714,456** | **4,097,764** |
| | | | | | | |
| Annual | 2020 | | | 1.18 | 714,456 | 4,097,764 |
| | 2021 | | | 1.30 | 714,456 | 4,097,764 |
| | 2022 | | | 1.15 | 714,456 | 4,097,764 |
| | 2023 | | | 1.12 | 714,456 | 4,097,764 |
| | 2024 | | | 1.25 | 714,456 | 4,097,764 |
| | **Max. of 5 years** | **1.0** | **N/A** | **1.30** | **714,456** | **4,097,764** |

**A:** UTM coordinates are in NAD83 Zone 16

The EKPC Cooper Project causes impacts above the $PM_{2.5}$ SIL for both the 24-hour and annual averaging periods. Further NAAQS and Class II Increment Analyses are required because these impacts are greater than the SILs.

**$PM_{2.5}$ SIL Modeling Analysis Results**

| Averaging Period | Year for Met. Data | SIL (µg/m³) | Significant Monitoring Concentration (µg/m³) | Maximum Primary PM2.5 Impact (µg/m³) | Maximum Secondary PM2.5 Impact (µg/m³) | Maximum Cumulative PM2.5 Impact (µg/m³) | UTM East (m) A | UTM North (m) A |
|---|---|---|---|---|---|---|---|---|
| 24-hour | 2020 | | | 3.64 | 0.1089 | 3.75 | 715,350 | 4,099,843 |
| | 2021 | | | 5.02 | 0.1089 | 5.13 | 714,456 | 4,097,764 |
| | 2022 | | | 4.88 | 0.1089 | 4.99 | 715,350 | 4,099,843 |
| | 2023 | | | 3.83 | 0.1089 | 3.94 | 714,438 | 4,097,770 |
| | 2024 | | | 3.84 | 0.1089 | 3.95 | 715,150 | 4,099,643 |
| | **Max. of 5 years** | **1.2** | **4** | **5.02** | **0.1089** | **5.13** | **714,456** | **4,097,764** |
| | | | | | | | | |
| Annual | 2020 | | | 0.35 | 0.0048 | 0.36 | 714,456 | 4,097,764 |
| | 2021 | | | 0.38 | 0.0048 | 0.39 | 714,456 | 4,097,764 |
| | 2022 | | | 0.35 | 0.0048 | 0.35 | 714,456 | 4,097,764 |
| | 2023 | | | 0.33 | 0.0048 | 0.33 | 714,456 | 4,097,764 |
| | 2024 | | | 0.36 | 0.0048 | 0.37 | 714,456 | 4,097,764 |
| | **Max. of 5 years** | **0.13** | **N/A** | **0.38** | **0.0048** | **0.39** | **714,456** | **4,097,764** |

**A:** UTM coordinates are in NAD83 Zone 16

The EKPC Cooper Project causes impacts above the CO SIL for both the 1-hour and 8-hour averaging periods. Further NAAQS Analysis is required because these impacts are greater than the SILs.

**CO SIL Modeling Analysis Results**

| Averaging Period | Year for Met. Data | SIL (µg/m³) | Significant Monitoring Concentration (µg/m³) | Maximum 1st High Impact (µg/m³) | UTM East (m) A | UTM North (m) A |
|---|---|---|---|---|---|---|
| 1-hour | 2020 | | | 11,485 | 715,350 | 4,099,943 |
| | 2021 | | | 11,683 | 715,350 | 4,100,043 |
| | 2022 | | | 11,597 | 715,350 | 4,099,943 |
| | 2023 | | | 10,412 | 715,250 | 4,099,973 |
| | 2024 | | | 11,089 | 715,350 | 4,100,043 |
| | **Max. of 5 years** | **2,000** | **N/A** | **11,683** | **715,350** | **4,100,043** |
| | | | | | | |
| 8-hour | 2020 | | | 3,398 | 715,350 | 4,099,943 |
| | 2021 | | | 2,497 | 715,150 | 4,099,743 |
| | 2022 | | | 2,343 | 715,350 | 4,099,943 |
| | 2023 | | | 2,381 | 715,350 | 4,099,943 |
| | 2024 | | | 3,169 | 715,350 | 4,099,943 |
| | **Max. of 5 years** | **500** | **575** | **3,398** | **715,350** | **4,099,943** |

**A:** UTM coordinates are in NAD83 Zone 16

## E. NAAQS Analyses Results

NAAQS analyses were conducted for CO, $NO_2$, $PM_{10}$, and $PM_{2.5}$. The modeling results demonstrate that the EKPC Cooper Project will be compliant with the NAAQS for each applicable pollutant and averaging period. The NAAQS analysis results are listed below:

**$NO_2$ NAAQS Modeling Analysis Results**

| Averaging Period | Year for Met. Data | NAAQS (µg/m³) | Maximum Impact (µg/m³) | Background Concentration (µg/m³) [C] | Combined Maximum Impact (µg/m³) | Exceeds NAAQS? | UTM East (m) [D] | UTM North (m) [D] |
|---|---|---|---|---|---|---|---|---|
| 1-hour [A] | **Max. 5-yr Avg.** | **188** | **161.7** | **9.4** | **171.1** | **No** | **715,750** | **4,092,343** |
| | | | | | | | | |
| Annual [B] | 2020 | | 6.93 | 1.9 | 8.81 | | 714,280 | 4,097,739 |
| | 2021 | | 7.34 | 1.9 | 9.22 | | 714,280 | 4,097,739 |
| | 2022 | | 6.85 | 1.9 | 8.73 | | 714,280 | 4,097,739 |
| | 2023 | | 6.61 | 1.9 | 8.49 | | 714,280 | 4,097,739 |
| | 2024 | | 7.00 | 1.9 | 8.88 | | 714,280 | 4,097,739 |
| | **Max. of 5 years** | **100** | **7.34** | **1.9** | **9.22** | **No** | **714,280** | **4,097,739** |

**A:** Evaluated the five-year average 8th highest daily maximum 1-hour output for comparison against the NAAQS.
**B:** Evaluated maximum modeled annual arithmetic mean impact from among the five years modeled for comparison against the NAAQS.
**C:** Background concentrations are based on ambient monitoring data from the Blount County, Tennessee site (Site ID 47-009-0101) for the three-year period from 2022 to 2024.
**D:** UTM coordinates are in NAD83 Zone 16

**$PM_{2.5}$ NAAQS Modeling Analysis Results**

| Averaging Period | Year for Met. Data | NAAQS (µg/m³) | Primary PM2.5 Impact (µg/m³) | Secondary PM2.5 Impact (µg/m³) | Background Concentration (µg/m³) [C] | Combined Maximum Impact (µg/m³) | Exceeds NAAQS? | UTM East (m) [D] | UTM North (m) [D] |
|---|---|---|---|---|---|---|---|---|---|
| 24-hour [A] | **Max. 5-yr Avg.** | **35** | **11.59** | **0.1089** | **17.00** | **28.70** | **No** | **714,350** | **4,095,843** |
| Annual [B] | **Avg. of 5 years** | **9** | **1.84** | **0.0048** | **7.10** | **8.94** | **No** | **714,455** | **4,097,995** |

**A:** Evaluated the five-year average 8th highest maximum 24-hour output for comparison against the NAAQS.
**B:** Evaluated average modeled annual arithmetic mean impact over the five years modeled for comparison against the NAAQS.
**C:** The 24-hour and annual average background concentrations are based on ambient monitoring data from the Somerset, Kentucky site (Site ID 21-199-0003) for the three-year period from 2022 to 2024.
**D:** UTM coordinates are in NAD83 Zone 16

**$PM_{10}$ NAAQS Modeling Analysis Results**

| Averaging Period | Year for Met. Data | NAAQS (µg/m$^3$) | Maximum Impact (µg/m$^3$) | Background Concentration (µg/m$^3$) [B] | Combined Maximum Impact (µg/m$^3$) | Exceeds NAAQS? | UTM East (m) [C] | UTM North (m) [C] |
|---|---|---|---|---|---|---|---|---|
| 24-hour [A] | **Max. 5-yr H6H** | **150** | **76.8** | **28** | **104.8** | **No** | **714,486** | **4,097,127** |

**A:** Evaluated the five-year maximum 6th highest 24-hour output for comparison against the NAAQS.
**B:** The 24-hour background concentration is based on ambient monitoring data from the Fayette County, KY site (Site ID 21-067-0012) for the three-year period from 2022 through 2024. The calculated background number is the 4$^{th}$ highest 24-hour average monitored concentration that occurred in 2022 through 2024.
**C:** UTM coordinates are in NAD83 Zone 16

**CO NAAQS Modeling Analysis Results**

| Averaging Period | Year for Met. Data | NAAQS (µg/m$^3$) | Maximum Impact (µg/m$^3$) | Background Concentration (µg/m$^3$) [B] | Combined Maximum Impact (µg/m$^3$) | Exceeds NAAQS? | UTM East (m) [C] | UTM North (m) [C] |
|---|---|---|---|---|---|---|---|---|
| 1-hour [A] | 2020 | | 11,475 | 800 | 12,275 | | 715,350 | 4,099,943 |
| | 2021 | | 11,138 | 800 | 11,938 | | 715,350 | 4,099,943 |
| | 2022 | | 10,781 | 800 | 11,581 | | 715,350 | 4,100,043 |
| | 2023 | | 10,307 | 800 | 11,107 | | 715,350 | 4,100,043 |
| | 2024 | | 10,697 | 800 | 11,497 | | 715,350 | 4,099,943 |
| | **Max. of 5 years** | **40,000** | **11,475** | **800** | **12,275** | **No** | **715,350** | **4,099,943** |
| | | | | | | | | |
| 8-hour [A] | 2020 | | 3,062 | 686 | 3,748 | | 715,350 | 4,099,043 |
| | 2021 | | 2,363 | 686 | 3,049 | | 715,350 | 4,099,043 |
| | 2022 | | 2,345 | 686 | 3,031 | | 715,350 | 4,099,043 |
| | 2023 | | 2,267 | 686 | 2,953 | | 715,350 | 4,099,043 |
| | 2024 | | 2,803 | 686 | 3,488 | | 715,350 | 4,100,043 |
| | **Max. of 5 years** | **10,000** | **3,062** | **686** | **3,748** | **No** | **715,350** | **4,099,943** |

**A:** Evaluated the 2$^{nd}$ highest modeled impacts from among the five years modeled for comparison against the NAAQS.
**B:** Background concentrations are based on ambient monitoring data from the Edmonson County, Kentucky site (Site ID 21-061-0501) for the two-year period of 2023-2024. The background concentration is based on the higher of each year's annual second maximum, non-overlapping 1-hour or 8-hour average.
**C:** UTM coordinates are in NAD83 Zone 16

**F. <u>Class II Increment Analysis</u>**

A PSD Increment Analysis was performed for $NO_2$, $PM_{10}$, and $PM_{2.5}$ using the same Class II modeling techniques described earlier. The maximum PSD Increment impacts correspond to source group 1 (GROUP01) for the $PM_{10}$ 24-hour run, source group 2 (GROUP02) for the $PM_{10}$ annual, and $PM_{2.5}$ annual runs, and source group 3 (GROUP03) for the $NO_2$ annual, and $PM_{2.5}$ 24-hour runs. The $PM_{2.5}$ increment modeling analysis accounts for both direct (AERMOD) and secondary (MERPs) $PM_{2.5}$ from the EKPC Cooper project and nearby $PM_{2.5}$ increment sources. Any source constructed or modified after the applicable PSD Increment major source baseline date is included in the model. There are no permitted sources not yet fully operative that would consume increment.

### $NO_2$ PSD Increment Analysis Results

| Averaging Period | Year for Met. Data | Class II PSD Increment ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Exceeds Increment? | UTM East (m) [B] | UTM North (m) [B] |
|---|---|---|---|---|---|---|
| Annual [A] | 2020 | | 5.94 | | 714,280 | 4,097,739 |
| | 2021 | | 6.22 | | 714,280 | 4,097,739 |
| | 2022 | | 5.79 | | 714,280 | 4,097,739 |
| | 2023 | | 5.62 | | 714,280 | 4,097,739 |
| | 2024 | | 6.01 | | 714,280 | 4,097,739 |
| | **Max. of 5 years** | **25** | **6.22** | **No** | **714,280** | **4,097,739** |

**A:** Evaluated highest impacts for each year modeled since annual $NO_2$ PSD Increment is not to be exceeded.
**B:** UTM coordinates are in NAD83 Zone 16

### $PM_{2.5}$ PSD Increment Analysis Results

| Averaging Period | Year for Met. Data | Class II PSD Increment ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Exceeds Increment? | UTM East (m) [C] | UTM North (m) [C] |
|---|---|---|---|---|---|---|
| 24-hour [A] | 2020 | | 3.51 | | 714,453 | 4,097,795 |
| | 2021 | | 4.35 | | 714,453 | 4,097,795 |
| | 2022 | | 3.43 | | 714,453 | 4,097,795 |
| | 2023 | | 3.83 | | 714,453 | 4,097,795 |
| | 2024 | | 3.23 | | 714,453 | 4,097,795 |
| | **Max. of 5 years** | **9** | **4.35** | **No** | **714,453** | **4,097,795** |
| | | | | | | |
| Annual [B] | 2020 | | 0.40 | | 714,453 | 4,097,795 |
| | 2021 | | 0.43 | | 714,453 | 4,097,795 |
| | 2022 | | 0.39 | | 714,453 | 4,097,795 |
| | 2023 | | 0.37 | | 714,453 | 4,097,795 |
| | 2024 | | 0.41 | | 714,453 | 4,097,795 |
| | **Max. of 5 years** | **4** | **0.43** | **No** | **714,453** | **4,097,795** |

**A:** Evaluated the 2nd highest 24-hour average modeled impact over the five years modeled for comparison against the PSD Increment.
**B:** Evaluated highest modeled annual arithmetic mean impact over the five years modeled for comparison against the PSD Increment.
**C:** UTM coordinates are in NAD83 Zone 16

### $PM_{10}$ PSD Increment Analysis Results

| Averaging Period | Year for Met. Data | Class II PSD Increment ($\mu g/m^3$) | Maximum Impact ($\mu g/m^3$) | Exceeds Increment? | EKPC Causes or Contributes? | UTM East (m) [B] | UTM North (m) [B] |
|---|---|---|---|---|---|---|---|
| 24-hour [A] | 2020 | | 36.89 | | | 714,250 | 4,096,443 |
| | 2021 | | 29.85 | | | 714,453 | 4,097,795 |
| | 2022 | | 24.23 | | | 714,250 | 4,096,443 |
| | 2023 | | 29.57 | | | 714,456 | 4,097,764 |
| | 2024 | | 26.59 | | | 714,250 | 4,096,443 |
| | **Max. of 5 years** | **30** | **36.89** | **Yes** | **No** | **714,250** | **4,096,443** |
| | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Annual | 2020 | | 2.54 | | | 714,453 | 4,097,795 |
| | 2021 | | 2.75 | | | 714,453 | 4,097,795 |
| | 2022 | | 2.46 | | | 714,453 | 4,097,795 |
| | 2023 | | 2.47 | | | 714,453 | 4,097,795 |
| | 2024 | | 2.62 | | | 714,453 | 4,097,795 |
| | **Max. of 5 years** | **17** | **2.75** | **No** | **N/A** | **714,453** | **4,097,795** |

**A:** Evaluated the 2nd highest 24-hour average modeled impact over the five years modeled for comparison against the PSD Increment.
**B:** UTM coordinates are in NAD83 Zone 16

Modeled exceedances of the PSD Increment were identified for 24-hour $PM_{10}$. A culpability analysis was conducted to determine if the EKPC Cooper Station project causes or contributes to these exceedances. The culpability analysis, in Appendix D, demonstrated that EKPC Cooper Station and the EKPC Cooper Station Project do not cause or contribute to the modeled exceedance with a 0.28201 $\mu g/m^3$ predicted maximum contribution concentration.

## G. Class I AQRV Analysis

There are six Class I areas located within 300 km of EKPC Cooper Station with the next closest Class I area more than 380 km away. The closest Class I area to EKPC Cooper Station is Mammoth Cave National Park (MCNP) which is located approximately 129 km west from Cooper Station. The Federal Land Managers (FLM) of these Class I areas have the authority to protect air quality, with two principle air quality impacts considered: PSD increments and air quality related values (AQRV).

Air Quality Related Values (AQRV) typically include visibility and surface deposition of sulfur and nitrogen. The AQRVs are considered by FLMs of Class I areas when determining if a proposed major source facility will have an adverse impact on the area. Impacts are addressed if the proposed project has an impact that exceeds the screening threshold as described by Federal Land Managers' (FLM) Air Quality Related Values Work Group (FLAG) guidance. In this guidance, the sum of the proposed project emissions of $SO_2$, $NO_X$, $PM_{10}$ and $H_2SO_4$ (in tpy) is divided by the distance from the source to the Class I area. This ratio is compared to the value of 10. This ratio is known as Q/D. If Q/D is 10 or less, the project is considered to have a negligible impact on the Class I area. If the Q/D value is greater than 10, then further analysis to evaluate impacts in the Class I area is warranted.

The sum of the emissions changes from the proposed C2 Co-Firing Project (subsection of the EKPC Cooper Station Project specific to the coal boiler, Project 2) result in a net increase in pollutants and are considered for Q/D analysis. The sum of emissions for $NO_X$, $PM_{10}$, $H_2SO_4$, and $SO_2$ are 850.96 tpy.

 

**Change in emissions due to C2 Co-Firing Project**

| Pollutant | "C2 Co-Firing Project" FLAG 2010 Approach Annual Emissions [A,B] (tpy) |
|---|---|
| $NO_X$ | +785.4 |
| $PM_{10}$ | +33.16 |
| $H_2SO_4$ | +11.2 |
| $SO_2$ | +21.2 |
| **Total** | **+850.96** |

**A:** Direct particulate includes all filterable and condensable $PM_{10}$, such as elemental carbon (EC), coarse PM (PMC), fine PM (PMF), $H_2SO_4$, secondary organic aerosols (SOA), inorganic condensable PM (e.g. $NO_3$), etc.
**B:** FLAG 2010 Approach: Q = [SO2 + NO2 + SO4 + EC + PMC + PMF + SOA + NO3 (max 24-hour basis)] x [8,760 hr/yr / 2000 lb/ton].

The Q/D analysis results are presented in the table below.

**Q/D Analysis for the C2 Co-Firing Project**

| Class I Area | Responsible FLM | Minimum Distance from Site – D (km) | Sum of Annualized Emissions – Q (tpy) | FLAG 2010 Q/D Approach (tpy/km) |
|---|---|---|---|---|
| Mammoth Cave National Park (MCNP) (KY) | NPS | 129 | 850.96 | 6.6 |
| Great Smoky Mountains National Park (GSMNP) (NC/TN) | NPS | 161 | | 5.3 |
| Joyce Kilmer / Slickrock (NC) | FS | 178 | | 4.8 |
| Cohutta Wilderness Area (GA) | FS | 221 | | 3.9 |
| Shining Rock (NC) | FS | 232 | | 3.7 |
| Linville Gorge (NC) | FS | 266 | | 3.2 |

The sum of emissions for the proposed CCGT EGU project (subsection of the EKPC Cooper Station Project specific to the combustion turbines, Project 1) result in a net increase in pollutants and are considered for Q/D analysis. The sum of emissions for $NO_X$, $PM_{10}$, $H_2SO_4$, and $SO_2$ are 609.4 tpy.

**Change in emissions due to CCGT EGU Project**

| Pollutant | "CCGT EGU Project" FLAG 2010 Approach Annual Emissions [A,B] (tpy) |
|---|---|
| $NO_X$ | +359.3 |
| $PM_{10}$ | +171.3 |
| $H_2SO_4$ | +49.8 |
| $SO_2$ | +29.0 |
| **Total** | **+609.4** |

**A:** Direct particulate includes all filterable and condensable $PM_{10}$, such as elemental carbon (EC), coarse PM (PMC), fine PM (PMF), $H_2SO_4$, secondary organic aerosols (SOA), inorganic condensable PM (e.g. $NO_3$), etc.
**B:** FLAG 2010 Approach: Q = [SO2 + NO2 + SO4 + EC + PMC + PMF + SOA + NO3 (max 24-hour basis)] x [8,760 hr/yr / 2000 lb/ton].

The Q/D analysis results are presented in the table below.

**Q/D Analysis for the CCGT EGU Project**

| Class I Area | Responsible FLM | Minimum Distance from Site – D (km) | Sum of Annualized Emissions – Q (tpy) | FLAG 2010 Q/D Approach (tpy/km) |
|---|---|---|---|---|
| Mammoth Cave National Park (MCNP) (KY) | NPS | 129 | 609.4 | 4.7 |
| Great Smoky Mountains National Park (GSMNP) (NC/TN) | NPS | 161 | | 3.8 |
| Joyce Kilmer / Slickrock (NC) | FS | 178 | | 3.4 |
| Cohutta Wilderness Area (GA) | FS | 221 | | 2.8 |
| Shining Rock (NC) | FS | 232 | | 2.6 |
| Linville Gorge (NC) | FS | 266 | | 2.3 |

## H. Class I PSD Increment Analysis

EKPC Cooper was required to perform Class I SIL evaluations at the potentially affected class I areas.

**Class I PSD SILs**

| Pollutant | Averaging Period | Class I SIL (µg/m$^3$) |
|---|---|---|
| $NO_2$ | Annual | 0.10 |
| $PM_{10}$ | 24-hour | 0.32 |
| | Annual | 0.16 |
| $PM_{2.5}$ | 24-hour | 0.27 |
| | Annual | 0.03 |

The AERMOD screening results for annual $NO_2$, 24-hour $PM_{2.5}$, and 24-hour $PM_{10}$ exceeded their respective SILs and as a result, EKPC conducted a more refined SIL screening analyses using the CALPUFF model.

Secondary PM2.5 formation impacts on the nearest Class I area were also considered. The nearest Class 1 area is Mammoth Cave National Park. Since all Class I areas are more than 50 km away from EKPC Cooper, the distance-dependent data for hypothetical sources was obtained from the U.S. EPA's MERPS View Qlik website ( https://www.epa.gov/scram/merps-view-qlik ).

**Expected Secondary $PM_{2.5}$ Impacts at Mammoth Cave National Park**

| Averaging Period | Precursor | Modeled Emissions from Hypothetical Source (tpy) | Modeled Impact from Hypothetical Source (µg/m$^3$) | Net Emissions Increase (tpy) | Secondary $PM_{2.5}$ Project Impact (µg/m$^3$) | Class I SIL (µg/m$^3$) |
|---|---|---|---|---|---|---|
| 24-hour | $NO_X$ | 1,000 | 0.063 | 1,116.5 | 0.07044 | |
| | $SO_2$ | 500 | 0.028 | 38.9 | 0.00220 | |
| | | | | **Total** | **0.07264** | **0.27** |
| | | | | | | |
| Annual | $NO_X$ | 1,000 | 0.0020 | 1,116.5 | 0.00225 | |
| | $SO_2$ | 500 | 0.0008 | 38.9 | 0.00006 | |
| | | | | **Total** | **0.00231** | **0.03** |

The hypothetical source is a source located in Barren County, KY from EPA's MERPs View Qlik website at a distance of 120 km (the distance to the closest Class I area from the project location). The hypothetical source emission rate represents the closest value available in MERPs View Qlik to the source-wide PTE for $NO_X$ and $SO_2$ for the project. The hypothetical source impacts are for the tall stack scenario.

## I. Class I SIL Modeling Results

The AERMOD screening results for annual $NO_2$, 24-hour $PM_{2.5}$, and 24-hour $PM_{10}$ exceeded their respective SILs and as a result, EKPC Cooper conducted a more refined SIL screening analyses using the CALPUFF model. EKPC Cooper utilized CALPUFF Version 5.8.5, Level 151214 and CALPOST Version 6.221, Level 082724 to determine possible impacts of the proposed facility in relation to the SILs at each of the 6 Class I areas.

The modeling analysis included only the main combustion sources (CTs, auxiliary boiler, and fuel gas dewpoint preheaters) as these sources are expected to contribute to long range transport. Fugitive emissions including those from roadways, material transfer and handling (e.g., conveyor transfers and storage piles), and building heating systems (HVAC heaters) were not included due to their very localized nature. Emergency engines were also excluded from the modeling due to their infrequent operation and very localized impacts.

The following tables show the results of the Class I SIL modeling analyses.

**Class I SIL Results – Mammoth Cave National Park**

| Pollutant | Averaging Period | Modeled Concentration (mg/m$^3$) | | | | SIL (µg/m$^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.129 | 0.142 | 0.150 | **0.150** | **0.27** | **No** |
| | Annual | 0.005 | 0.005 | 0.005 | **0.005** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.056 | 0.070 | 0.078 | **0.078** | **0.30** | **No** |
| | Annual | 0.003 | 0.003 | 0.003 | **0.003** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.009 | 0.011 | 0.011 | **0.011** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**Class I SIL Results – Great Smoky Mountains National Park**

| Pollutant | Averaging Period | Modeled Concentration (mg/m$^3$) | | | | SIL (µg/m$^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.126 | 0.119 | 0.114 | **0.126** | **0.27** | **No** |
| | Annual | 0.004 | 0.004 | 0.004 | **0.004** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.054 | 0.046 | 0.041 | **0.054** | **0.30** | **No** |
| | Annual | 0.002 | 0.002 | 0.002 | **0.002** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.006 | 0.007 | 0.006 | **0.007** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**Class I SIL Results – Joyce Kilmer / Slickrock Wilderness Area**

| Pollutant | Averaging Period | Modeled Concentration ($mg/m^3$) | | | | SIL ($\mu g/m^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.096 | 0.108 | 0.114 | **0.114** | **0.27** | **No** |
| | Annual | 0.004 | 0.004 | 0.004 | **0.004** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.023 | 0.036 | 0.041 | **0.041** | **0.30** | **No** |
| | Annual | 0.001 | 0.002 | 0.002 | **0.002** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.005 | 0.005 | 0.006 | **0.006** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**Class I SIL Results – Cohutta Wilderness Area**

| Pollutant | Averaging Period | Modeled Concentration ($mg/m^3$) | | | | SIL ($\mu g/m^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.096 | 0.084 | 0.094 | **0.096** | **0.27** | **No** |
| | Annual | 0.003 | 0.003 | 0.004 | **0.004** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.024 | 0.011 | 0.021 | **0.024** | **0.30** | **No** |
| | Annual | 0.001 | 0.001 | 0.001 | **0.001** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.004 | 0.003 | 0.004 | **0.004** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**Class I SIL Results – Shining Rock Wilderness Area**

| Pollutant | Averaging Period | Modeled Concentration ($mg/m^3$) | | | | SIL ($\mu g/m^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.097 | 0.100 | 0.082 | **0.100** | **0.27** | **No** |
| | Annual | 0.003 | 0.003 | 0.003 | **0.003** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.024 | 0.027 | 0.010 | **0.027** | **0.30** | **No** |
| | Annual | 0.001 | 0.001 | 0.001 | **0.001** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.003 | 0.003 | 0.003 | **0.003** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**Class I SIL Results – Linville Gorge Wilderness Area**

| Pollutant | Averaging Period | Modeled Concentration ($mg/m^3$) | | | | SIL ($\mu g/m^3$) | Exceeds SIL? |
|---|---|---|---|---|---|---|---|
| | | 2018 | 2019 | 2020 | MAX | | |
| $PM_{2.5}$ [A] | 24-hour | 0.085 | 0.118 | 0.094 | **0.118** | **0.27** | **No** |
| | Annual | 0.003 | 0.003 | 0.003 | **0.003** | **0.05** | **No** |
| | | | | | | | |
| $PM_{10}$ | 24-hour | 0.013 | 0.045 | 0.021 | **0.045** | **0.30** | **No** |
| | Annual | 0.001 | 0.001 | 0.001 | **0.001** | **0.20** | **No** |
| | | | | | | | |
| $NO_2$ | Annual | 0.003 | 0.004 | 0.004 | **0.004** | **0.10** | **No** |

**A:** Impacts include secondary contribution total from both project $NO_X$ and $SO_2$ emissions.

**J. Additional Impacts Analysis**

Three additional impacts analyses were performed: a growth analysis, a soil and vegetation analysis, and a visibility analysis. The EKPC Cooper project will result in minimal residential and commercial growth and negligible growth impacts. The soil and vegetation impacts were assessed against the secondary NAAQS standards and also evaluated using the methodology from the U.S. EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (December 1980).

| Pollutant | Averaging Period | Maximum Impact | | Screening Concentrations for Exposure to Ambient Air Concentrations | | | Secondary NAAQS ($\mu g/m^3$) | Selected Soils and Vegetation Screening Threshold ($\mu g/m^3$) | Threshold Exceeded? |
|---|---|---|---|---|---|---|---|---|---|
| | | ($\mu g/m^3$) | Note | Sensitive ($\mu g/m^3$) | Intermediate ($\mu g/m^3$) | Resistant ($\mu g/m^3$) | | | |
| $NO_2$ | 4-hour | 165.8 | A | 3,760 | 6,400 | 16,920 | N/A | 3,760 | No |
| | 8-hour | 136.2 | A | 3,760 | 7,520 | 15,040 | N/A | 3,760 | No |
| | 1-month | 23.1 | A | - | 564 | - | N/A | 564 | No |
| | Annual | 9.2 | A | - | 94 | - | 100 | 94 | No |
| CO | 1-week | 3,062 | B | 1,800,000 | - | 18,000,000 | N/A | 1,800,000 | No |
| $PM_{10}$ | 24-hour | 104.8 | C | - | - | - | 150 | 150 | No |
| $PM_{2.5}$ | 24-hour | 28.7 | D | - | - | - | 35 | 35 | No |
| | Annual | 8.9 | E | - | - | - | 15 | 15 | No |

**1:** Results from the NAAQS Analysis where modeled impacts exceeded the SIL. Additional notes explaining the basis of the modeled impacts are listed below.

A = $NO_2$ impacts for the 4-hour, 8-hour, and monthly averaging periods were generated using the same modeling inputs as the 1-hour $NO_2$ NAAQS analyses in separate Soils & Vegetation modeling files. Annual $NO_2$ impacts were retrieved from NAAQS analysis. Background concentrations are based on ambient monitoring data from the Blount County, Tennessee site (Site ID 47-009-0101) for the three-year period of 2022 to 2024.

B = Maximum 8-hour average CO impact from the NAAQS Analysis. No 1-week averaging period is available in AERMOD, so the 8-hour results were used as a conservative estimate for the weekly impacts.

C = Maximum 24-hour average $PM_{10}$ impact plus the 4th highest 24-hour average monitored concentration that occurred in 2022 through 2024 at the Fayette County, Kentucky site (Site ID 21-067-0012).

D = Five-year average 8th highest $PM_{2.5}$ impact plus the three-year average 98th percentile background concentration from the Somerset, Kentucky site (Site ID 21-199-0003) for the three-year period from 2022 to 2024. Refer to the culpability analysis completed for the 24-hour NAAQS analysis.

E = Maximum five-year average annual $PM_{2.5}$ impacts plus the three-year average annual background concentration from the Somerset, Kentucky site (Site ID 21-199-0003) for the three-year period from 2022 to 2024.

**2:** Screen concentrations are based on Table 3.1 in *A Screening Procedure for Impact of Air Pollution Sources on Plants, Soil and Animals*, U.S. EPA, December 12, 1980. Minimum values noted if range listed.

EKPC Cooper conducted a visibility analysis at the closest potentially sensitive Class II area, General Burnside State Park, using U.S. EPA's VISCREEN Model following the guidelines in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/R-92-023, October 1992) to assess potential plume impairment. The plume had a $\Delta E$ (Delta E) less than 2.0, which signifies the plume will not be perceptible. The contrast was also less than the threshold of 0.05, which indicates the plume is not perceptible by contrast or color.

## SECTION 3 – EMISSIONS, LIMITATIONS AND BASIS

**Emission Unit #1 Indirect Heat Exchanger (Unit 1)**

| Emission Unit #1 Indirect Heat Exchanger (Unit 1) | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | 0.23 lb/MMBtu | 401 KAR 61:015, Section 4(1)(a) | 97.4 lb/ton (uncontrolled factor); Historic KYEIS Data | PM CEMS |
| | 0.030 lb/MMBtu | Consent Decree entered September 24, 2007, paragraph 87 | | Performance Testing |
| Opacity | 40% | 401 KAR 61:015 Section (4)(1)(c) | N/A | COM System |
| $SO_2$ | 3.3 lb/MMBtu | 401 KAR 61:015 Section 5(1) | 3.16 lb/ton; Historic KYEIS Data | $SO_2$ CEMS |
| **40 CFR 63, Subpart UUUUU Emission Limits** | | | | |
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM (Filterable) | 0.030 lb/MMBtu **OR** 0.30 lb/MWh (Gross) | Item 1.(a) in Table 2 to 40 CFR 63, Subpart UUUUU | 97.4 lb/ton (uncontrolled factor), Historic KYEIS Data | Quarterly Stack Testing **OR** PM CEMS |
| **AND** | | | | |
| Hydrogen Chloride (HCl) | 0.0020 lb/MMBtu **OR** 0.02 lb/MWh | [Item 1.(b) in Table 2 to 40 CFR 63, Subpart UUUUU] | 0.6624 lb/ton; Historic KYEIS Date | Quarterly Stack Testing [Item 3 in Table 5 to 40 CFR 63, Subpart UUUUU] |
| **AND** | | | | |
| Mercury (Hg) | 1.2 lb/TBtu **OR** 0.013 lb/GWh | [Item 1.(b) in Table 2 to 40 CFR 63, Subpart UUUUU] | 0.0003677 lb/ton; Historic KYEIS Data | Quarterly Stack Testing **OR** Sorbent Trap Monitoring System |

**Emission Unit #1 Indirect Heat Exchanger (Unit 1)**

**Initial Construction Date:** 1965; ESP installed 1971 and rebuilt 1989; Low $NO_X$ burners installed 1993; Duct rerouted to DFGD and PJFF completed April 2016

**Process Description:**
Pulverized Coal-fired, Dry Bottom, Wall-fired Unit

| | |
|---|---|
| Primary Fuel: | Pulverized Coal |
| Startup Fuel: | Number Two Fuel Oil |
| Maximum Continuous Rating: | 1,080 MMBtu/hr |
| Control Devices: | Electrostatic Precipitator (ESP); Low $NO_x$ Burners; Dry Flue Gas Desulfurization (DFGD); and Pulse Jet Fabric Filter (PJFF) (DFGD and PJFF shared with Unit 2); MerControl 7895 Injection |

**Applicable Regulation:**
**401 KAR 51:160**, *$NO_X$ requirements for large utility and industrial boilers* applies to $NO_X$ budget units that are electric generating units or industrial boilers that does not qualify for an exemption under 401 KAR 51:160, Section 2.

**401 KAR 51:210**, *CAIR $NO_x$ annual trading program* applies to CAIR $NO_x$ units in Kentucky that are subject to 40 CFR 96.104, which applies to any stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:220**, *CAIR $NO_x$ ozone season trading program* applies to CAIR $NO_x$ ozone season units in Kentucky which are subject to 40 CFR 96.304, which applies to any stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:230**, *CAIR $SO_2$ trading program* applies to CAIR $SO_2$ units under the CAIR $SO_2$ Trading Program located in Kentucky which are subject to 40 CFR 96.204 which applies to stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:240,** *Cross-State Air Pollution Rule (CASPR) $NO_X$ annual trading program* applies to CSAPR $NO_X$ Annual units in Kentucky subject to 40 CFR 97.404 as published July 1, 2017. 40 CFR 97.404 applies to any stationary, fossil-fuel-fired boiler serving on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:250**, *Cross-State Air Pollution Rule (CASPR) $NO_X$ ozone season group 2 trading program*, applies to CSAPR $NO_X$ Ozone Season Group 2 units in Kentucky subject to 40 CFR 97.804, as published July 1, 2017. 40 CFR 97.804 applies to any stationary, fossil-fuel-fired boiler serving at any time, on or after January 1, 2005, a generator with a name plate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:260,** *Cross-State Air Pollution Rule (CASPR) $SO_2$ group 1 trading program,* applies to CSAPR $SO_2$ Group 1 units in Kentucky subject to 40 CFR 97.604 as published July 1, 2017. 40 CFR 67.604 applies to any stationary, fossil-fuel-fired boilers serving at any time on or after January 1, 2005, a generator with a nameplate capacity of 25 MWe producing electricity for sale.

| Emission Unit #1 Indirect Heat Exchanger (Unit 1) |
|---|
| **401 KAR 52:060,** *Acid rain permits* applies to affected sources and affected units under the Acid Rain Program, pursuant to 42 U.S.C. 7651 to 7651o. Applicability under 40 CFR 72.6 includes a unit listed in Table 1 of 40 CFR 73.10(a), and Cooper Units 1 and 2 are included in this table.<br><br>**401 KAR 61:015**, *Existing indirect heat exchangers* applies to an indirect heat exchanger having a heat input capacity of more than one (1) MMBtu/hr for which construction commenced before August 17, 1971<br><br>**401 KAR 63:002, Section 2(4)(yyyy)**, 40 CFR 63.9980 through 63.10042, Tables 1 through 9, and Appendices A through E (**Subpart UUUUU**), *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* applies to owners and operators of coal- or oil-fired electric generating units, as defined in 40 CFR 63.10042<br><br>**40 CFR 52, Subpart S** *Kentucky* (BART SIP), incorporates emission limits and control device requirements from the consent decree entered September 24, 2007, as part of the Regional Haze state implementation plan.<br><br>**40 CFR Part 75,** *Continuous Emissions Monitoring* applies to units subject to Acid Rain emission limitations or reduction requirements for $SO_2$ or $NO_x$.<br><br>**Non-applicable Regulation:**<br>**401 KAR 63:020**, *Potentially hazardous matter and toxic substances* does not apply as emissions of hazardous and/or toxic substances are subject to the provisions of another regulation.<br><br>**Comments:**<br>APE20250001 removed the option to burn wood as a fuel.<br><br>Stack information and maximum coal combustion were updated in POC table from supplemental application submitted under APE20250001.<br><br>The unit meets the exemption for **40 CFR Part 64,** *Compliance Assurance Monitoring* (For PM) under 40 CFR 64.2(b)(1)(vi) by using PM CEMS to demonstrate compliance with the applicable PM limitation under 401 KAR 61:015.<br><br>Emission factors for criteria pollutants, greenhouse gases, antimony, arsenic, chromium, cobalt, manganese, mercury, hydrochloric acid and hydrofluoric acid are based off the 2017 emissions inventory survey and were updated during the renewal under APE20180001.<br><br>MerControl 7895 uses $CaBr_2$ for Hg control, which hydrolyzes at very high temperatures to form HBr by the following mechanism: $CaBr_2 + H_2O \rightarrow CaO + 2HBr$.<br><br>PTE calculations assume all excess $CaBr_2$ mixes with steam in the flue gas to form HBr. However, the PJFF and DFGD provide approximately 95% control of the HBr.<br><br>For 401 KAR 61:015 Emissions limits, Pulaski County is class III for sulfur oxides and class III for particulates. See 401 KAR 50:020. $Y=1.3152*(1080+2089)^{-0.2159}$=0.23lb/MMBtu limit for PM. |

**Emission Unit #2 Indirect Heat Exchanger (Unit 2n)**

| Emission Unit #2 Indirect Heat Exchanger (Unit 2n) | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| Opacity | 40% | 401 KAR 61:015, Section 4(1)(c) | N/A | COM System |
| PM | 0.23 lb/MMBtu | 401 KAR 61:015, Section 4(1)(a) | 0.70 lb/ton (controlled factor); AP-42 Table 1.1-5 | PM CEMS |
| | 0.030 lb/MMBtu | Consent Decree entered on September 24, 2007, paragraph | | Performance Testing |
| $SO_2$ | 3.3 lb/MMBtu (100% coal)<br><br>2.2 lb/MMBtu (100% gas) | 401 KAR 61:015, Section 5(1) | 76.7 lb/ton; AP-42 Table 1.1-3 | $SO_2$ CEMS |
| | 95% Rolling Average $SO_2$ Removal Efficiency **OR** 0.100 lb/MMBtu 30-Day Rolling Average Emission Rate | Consent Decree entered on September 24, 2007, paragraph 65 | | |
| $NO_X$ | 0.080 lb/MMBtu 30-day Rolling Average Emission Rate | Consent Decree entered on September 24, 2007, paragraph 53 | 9.82 lb/ton (coal); AP-42 Table 1.1-3<br><br>291 lb/MMscf (gas); AP-42 Table 1.4-1 | $NO_x$ CEMS |
| | 0.080 lb/MMBtu, 30-day Rolling Average | 401 KAR 51:017 (BACT) | | $NO_x$ CEMS |
| | 878 tons/yr | 401 KAR 51:017 (BACT) | | $NO_x$ CEMS |
| CO | 0.12 lb/MMBtu, 3-hour average | 401 KAR 51:017 (BACT) | 0.44 lb/ton (coal); AP-42 Table 1.1-3<br><br>127.2 lb/MMscf (gas)<br>BACT Limit | Performance Testing |
| | 1,278 tons/yr | 401 KAR 51:017 (BACT) | | |
| VOC | 0.0055 lb/MMBtu, 3-hour average | 401 KAR 51:017 (BACT) | 0.05 lb/ton (coal); AP-42 Table 1.1-19<br><br>5.72 lb/MMscf (gas); | Performance Testing |
| | 58 tons/yr | 401 KAR 51:017 | | |

| Emission Unit #2 Indirect Heat Exchanger (Unit 2n) | | | | |
|---|---|---|---|---|
| | | (BACT) | AP-42 Table 1.4-2 | |
| $PM/PM_{10}/PM_{2.5}$ | 0.030 lb/MMBtu, 3-hour average | 401 KAR 51:017 (BACT) | 0.70 lb/ton (coal) (controlled factor); AP-42 Table 1.1-5<br><br>3.60 lb/MMscf (gas); AP-42 Table 1.4-2 | Performance Testing |
| | 310 tons/yr | 401 KAR 51:017 (BACT) | | |
| $H_2SO_4$ | 0.005 lb/MMBtu, 3-hour average | 401 KAR 51:017 (BACT) | 0.13 lb/ton (coal); Engineering Calcs<br><br>0.01 lb/MMscf (gas); Engineering Calcs | Performance Testing |
| | 57 tons/yr | 401 KAR 51:017 (BACT) | | |
| GHG | 2,074 lb/MWh-g, 12-month rolling average | 401 KAR 51:017 (BACT) | 40 CFR 98, Table C-1 and Table C-2 | Part 75 procedures |
| | 2,146,866 tons/yr | 401 KAR 51:017 (BACT) | | |
| **40 CFR 63 UUUUU Limits** | | | | |
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM (filterable) | 0.030 lb/MMBtu<br>**OR**<br>0.30 lb/MWh (Gross) | Item 1.a. to Table 2 to 40 CFR 63, Subpart UUUUU | 0.70 lb/ton (controlled factor); AP-42 Table 1.1-5 | Quarterly stack testing<br>**OR**<br>PM CEMS [Item 1. in Table 5. and Table 7 to 40 CFR 63, Subpart UUUUU |
| **AND** | | | | |
| Hydrogen Chloride (HCl) | 0.0020 lb/MMBtu<br>**OR**<br>0.020 lb/MWh | Item 1. b. to Table 2 to 40 CFR 63, Subpart UUUUU | 1.2 lb/ton; AP-42 Table 1.1-15 | Quarterly Stack Testing [Item 3 in Table 5 to 40 CFR 63, Subpart UUUUU] |
| **AND** | | | | |
| Mercury (Hg) | 1.2 lb/TBtu<br>**OR**<br>0.013 lb/GWh | Item 1. c. to Table 2 to 40 CFR 63, Subpart UUUUU | 6.3E-7 lb/ton; AP-42 Table 1.1-17 | Quarterly Stack Testing<br>**OR**<br>Sorbent Trap Monitoring System<br>[Item 4 in Table 5 to 40 CFR 63, Subpart UUUUU] |

**Initial Construction Date:** 1969

**Modification Date:** Proposed September 2026 (natural gas firing or co-firing with coal).

Low $NO_x$ burners installed 1994; FGD, SCR and PJFF installed in 2012; FGD and PJFF in operation since Jue 30, 2012; Duct reroute to DFGD and PJFF completed April 2016; PM CEMS installed on or before December 31, 2012.

**Emission Unit #2 Indirect Heat Exchanger (Unit 2n)**

**Process Description:**

Pulverized Coal-fired, Dry Bottom, Wall-fired Unit

| | |
|---|---|
| Primary Fuel: | Pulverized Coal, Natural Gas, or Co-fire |
| Startup Fuel: | Number Two Fuel Oil and/or Natural Gas |
| Maximum Continuous Rating: | 2,433 MMBtu/hr |
| Control Devices: | Low $NO_X$ burners; Dry Flue Gas Desulfurization (DFGD); Selective Catalytic Reduction (SCR); Pulse Jet Fabric Filter (PJFF); (DFGD and PJFF shared with Unit 1); and FuelSolv Treatment |

**Applicable Regulation:**

**401 KAR 51:017**, *Prevention of significant deterioration of air quality* applies to a major modification project at an existing major stationary source that causes a significant emissions increase and a significant net emissions increase as provided in 401 KAR 51:017, Section 1(4)(a)1. through 3.

**401 KAR 51:160**, *$NO_x$ requirements for large utility and industrial boilers* applies to $NO_X$ budget units that are electric generating units or industrial boilers that does not qualify for an exemption under 401 KAR 51:160, Section 2.

**401 KAR 51:210**, *CAIR $NO_x$ annual trading program* applies to CAIR $NO_x$ units in Kentucky that are subject to 40 CFR 96.104, which applies to any stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:220**, *CAIR $NO_x$ ozone season trading program* applies to CAIR $NO_x$ ozone season units in Kentucky which are subject to 40 CFR 96.304, which applies to any stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:230**, *CAIR $SO_2$ trading program* applies to CAIR $SO_2$ units under the CAIR $SO_2$ Trading Program located in Kentucky which are subject to 40 CFR 96.204 which applies to stationary, fossil-fuel-fired boiler serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:240** *Cross-State Air Pollution (CSAPR) $NO_x$ annual trading program* applies to CSAPR $NO_X$ Annual units in Kentucky subject to 40 CFR 97.404 as published July 1, 2017. 40 CFR 97.404 applies to any stationary, fossil-fuel-fired boiler serving on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:250**, *Cross-State Air Pollution (CSAPR) $NO_x$ ozone season group 2 trading program* applies to CSAPR $NO_X$ Ozone Season Group 2 units in Kentucky subject to 40 CFR 97.804, as published July 1, 2017. 40 CFR 97.804 applies to any stationary, fossil-fuel-fired boiler serving at any time, on or after January 1, 2005, a generator with a name plate capacity of more than 25 MWe producing electricity for sale.

**401 KAR 51:260**, *Cross-State Air Pollution (CSAPR) $SO_2$ group 1 trading program* applies to CSAPR $SO_2$ Group 1 units in Kentucky subject to 40 CFR 97.604 as published July 1, 2017. 40 CFR 67.604 applies to any stationary, fossil-fuel-fired boilers serving at any time on or after January 1, 2005, a generator with a nameplate capacity of 25 MWe producing electricity for sale.

| **Emission Unit #2 Indirect Heat Exchanger (Unit 2n)** |
|---|
| **401 KAR 52:060**, *Acid rain permits* applies to affected sources and affected units under the Acid Rain Program, pursuant to 42 U.S.C. 7651 to 7651o. Applicability under 40 CFR 72.6 includes a unit listed in Table 1 of 40 CFR 73.10(a), and Cooper Units 1 and 2 are included in this table.<br><br>**401 KAR 61:015**, *Existing indirect heat exchangers* applies to each affected facility commenced before August 17, 1971. "Commence" is defined under 401 KAR 61:001: an owner or operator has undertaken a continuous program of construction, modification, or reconstruction of an affected facility, or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction, modification, or reconstruction of an affected facility. A "modification" means any physical change in, or change in the method of operation of, an affected facility that increases the amount of an air pollutant (to which a standard applies) emitted into the atmosphere by that facility or that results in the emission of an air pollutant (to which a standard applies) into the atmosphere not previously emitted. The project to co-fire natural gas with coal does not result in an increase in the amount of air pollutants emitted to which a standard applies. Therefore, the commence construction date remains 1969.<br><br>**401 KAR 63:002, Section 2(4)(yyyy),** 40 CFR 63.9980 through 63.10042, Tables 1 through 9, and Appendices A through E (**Subpart UUUUU**), *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* applies to owners and operators of coal and oil fired EGUs as defined in 40 CFR 63.10042<br><br>**40 CFR 52, Subpart S**¸ *Kentucky* (BART SIP) incorporates emission limits and control device requirements from the consent decree entered September 24, 2007 as part of the Regional Haze state implementation plan.<br><br>**40 CFR Part 75**, *Continuous Emissions Monitoring*, applies to units subject to Acid Rain emission limitations or reduction requirements for $SO_2$ or $NO_x$.<br><br>**Non-applicable Regulations:**<br>**401 KAR 60:005, Section 2(2)(b),** 40 CFR 60.40Da through 60.52Da (**Subpart Da**), *Standards of Performance for Electric Utility Steam Generating Units* does not apply, as C2 is considered an existing unit under 40 CFR 60.40Da(a)(1) and the change to co-fire natural gas is not considered a *modification* under 40 CFR 60.14(a). The change to co-fire natural gas is not considered a *modification* because the change does not result in an emissions increase.<br><br>**401 KAR 63:020**, *Potentially hazardous matter and toxic substances* does not apply as emissions of hazardous and/or toxic substances are subject to the provisions of another regulation.<br><br>**Comments:**<br>For 401 KAR 61:015 Emissions limits, Pulaski County is class III for sulfur oxides and class III for particulates. See 401 KAR 50:020. $Y=1.3152*(1080+2089)^{-0.2159}=0.23$lb/MMBtu limit for PM;<br><br>The unit meets the exemption for **40 CFR Part 64,** *Compliance Assurance Monitoring* (For PM) under 40 CFR 64.2(b)(1)(vi) by using PM CEMS to demonstrate compliance with the applicable PM limitation under 401 KAR 61:015 |

**Emission Unit #3 Coal Handling Operations**

**Emission Unit #3 Coal Handling Operations**

**Initial Construction Date:** Prior to 1970

**Process Description:**
Truck unloading, receiving hoppers (two), coal conveyors/transfer points (five), reclaim hoppers, crusher, coal stacker, coal stockpile, and yard area

| | |
|---|---|
| Maximum Continuous Rating: | 600 tons/hr* |
| Maximum Annual Capacity: | 463,566 tpy upon the Commercial Operation Date |
| Control Devices: | DusTreat CF9156 and DusTreat DC6109; additives to reduce fugitive emissions |

*After Commercial operation date as defined in Section D of Permit V-26-012, annual coal throughput will be limited to 463,566 tpy.

**Applicable Regulation:**
**401 KAR 63:010**¸ *Fugitive emissions* applies to each apparatus, operation, or road that emits or could emit fugitive emissions not elsewhere subject to an opacity standard

**Comments:**
Emission factors are from AP-42 Chapter 13.2

Although this is a non-modified unit, PTE calculations are now based on coal's Maximum Annual Capacity, which has been updated as a result of the Unit 2 co-fire project.

The facility plans to remove EU 03-01, 03-02, 03-04, 03-06, 03-07, and 03-08 as part of the PSD CT/EGU Conversion project but would like to retain the equipment in the permit and KYEIS until the new coal handling units have been constructed and the existing coal handling activities have been permanently demolished.

**Emission Unit #4 Unit 2 Cooling Tower**

**Emission Unit #4 Unit 2 Cooling Tower**

| Pollutant | Emission Limit or Standard | Regulatory Basis for Emission Limit or Standard | Emission Factor Used and Basis | Compliance Method |
|---|---|---|---|---|
| PM | *$P \leq 0.5$, $E=2.34$; $0.5<P\leq 30$, $E=3.59P^{0.62}$; $P>30$, $E=17.31P^{0.16}$ | 401 KAR 59:010, Section 3(2) | 0.0062 lb/MMgal, APE20070002 Application | Assumed |
| Opacity | 20% | 401 KAR 59:010, Section 3(1)(a) | N/A | Assumed |

*Where P is process weight rate in tons/hr and E is maximum allowable emission weight rate in lb/hr

**Initial Construction Date:** 2007

**Process Description:**

| | |
|---|---|
| Maximum Continuous Rating: | 150,000 gal/min (circulating water) |
| Control Devices: | Drift Eliminators |
| Drift Rate: | 0.0005% |
| Construction Commenced: | 2007 |

| Emission Unit #4 Unit 2 Cooling Tower |
|---|
| **Applicable Regulation:**<br>**401 KAR 59:010**, *New Process Operations* applies to each affected facility or source, associated with a process operation, which is not subject to another emission standard with respect to particulates<br><br>**Precluded Regulation:**<br>**401 KAR 63:002, Section 2(4)(j)**, 40 CFR 63.400 through 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers* applies to industrial process cooling towers operated with chromium-based water treatment chemicals. This unit is not operated with chromium-based water treatment chemicals.<br><br>**Comments:**<br>N/A |

**Emission Unit #5 Two Fly Ash and Lime Waste Silos A and B (Pneumatic Loading)**

| **Emission Unit #5 Two Fly Ash and Lime Waste Silos A and B (Pneumatic Loading)** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | *$P \leq 0.5$, $E=2.34$; $0.5<P\leq 30$, $E=3.59P^{0.62}$; $P>30$, $E=17.31P^{0.16}$ | 401 KAR 59:010, Section 3(2) | 0.27 lb/ton Historic KYEIS Data | Assumed |
| Opacity | 20% | 401 KAR 59:010, Section 3(1)(a) | N/A | |

*Where P is process weight rate in tons/hr and E is maximum allowable emission weight rate in lb/hr

**Initial Construction Date:** 1993

**Process Description:**

Maximum Continuous Rating: 31 tons/hr (each)
Control Devices: Fabric Filter Baghouse

**Applicable Regulation:**
**401 KAR 59:010,** *New process operations* applies to each affected facility or source, associated with a process operation, which is not subject to another emission standard with respect to particulates.

**Comments:**

**40 CFR Part 64**, *Compliance Assurance Monitoring* (CAM) was previously identified as applicable to these units. However, the Division identified that the uncontrolled PTE for both units combined is less than 100 tpy. Therefore, CAM does not apply and was removed from the permit for these units.

**Emission Unit #8 Emergency Diesel Generator Engine**

| **Emission Unit #8 Emergency Diesel Generator Engine** |
|---|
| **Initial Construction Date:** 1998<br>**Process Description:**<br>12.18 MMBtu/hr (89 gal/hr) diesel-fired CAT 3516 emergency generator engine<br>2,145 HP<br>**Applicable Regulation:**<br>**401 KAR 63:002, Section 2(4)(eeee),** 40 CFR 63. 6580 through 63.6675, Tables 1a through 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* applies to stationary reciprocating internal combustion engines (RICE) located at major or area sources of HAP emissions. |

**Emission Unit #9 Pebble Lime, Fly Ash, and Waste Product Handling System**

| **Emission Unit #9 Pebble Lime, Fly Ash, and Waste Product Handling System** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | *$P \leq 0.5$, $E=2.34$; $0.5<P\leq 30$, $E=3.59P^{0.62}$; $P>30$, $E=17.31P^{0.16}$ | 401 KAR 59:010, Section 3(2) | See Process Description | Assumed |
| Opacity | 20% | 401 KAR 59:010, Section | N/A | Visual Observation, EPA Reference Method 9 |

**Initial Construction Date:** 2010

**Process Description:**

| **Emission Point** | **Description** | **Maximum Continuous Rating (Tons/hr)** | **Emission Factor Used and Basis** | **Control Device** |
|---|---|---|---|---|
| 09-01 | Fly Ash and Waste Product Silo | 80 | 0.03389 lb/ton; Historic KYEIS Data | Fabric Filter |
| 09-03 | Vacuum Systems 1 & 2 | 40 (each) | 1.6305 lb/ton; Historic KYEIS Data | |
| 09-04 | Pebble Lime Silo | 19 | 1.7163 lb/ton; Historic KYEIS Data | |
| 09-05 | Hydrator Feed Bins 1 & 2 | 25 (each) | 0.02422 lb/ton; Historic KYEIS Data | |
| 09-06 | Lime Hydrator 1 & 2 | 19 (each) | 0.4667 lb/ton; Historic KYEIS Data | |
| 09-07 | Hydrated Lime | 50 | 1.3044 lb/ton; | |

**Emission Unit #9 Pebble Lime, Fly Ash, and Waste Product Handling System**

| | | | | |
|---|---|---|---|---|
| | Silo | | Historic KYEIS Data | |

**Applicable Regulation:**
**401 KAR 59:010,** *New process operations* applies to each affected facility or source, associated with a process operation, which is not subject to another emission standard with respect to particulates

**40 CFR Part 64**, *Compliance Assurance Monitoring* (For PM) applies to units 09-03and 09-07, as these are units located at a major source, subject to a PM emission limitation or standard, use a control device to achieve compliance with the emission limit or standard, and have the uncontrolled potential to emit greater than 100 tpy of PM.

**Comments:**
Emission factors for $PM_{10}$ and $PM_{2.5.}$ are sourced from AP-42 Table B.2.2.Category 5 Process: Calcining and Other Heat Reaction

**Emission Unit #10 Paved Roadways**

**Emission Unit #10 Paved Roadways**

**Initial Construction Date:** Prior to 1970, additional road and traffic added 2010, additional changes in 2026

**Process Description:**
Paved Haul roads throughout the plant with an average of 11,612 VMT per year

**Applicable Regulation:**
**401 KAR 63:010**, *Fugitive emissions* applies to each apparatus, operation, or road that emits or could emit fugitive emissions not elsewhere subject to an opacity standard.

**Emission Unit #12 Communication Tower Emergency Generator**

**Emission Unit #12 Communication Tower Emergency Generator**

**Initial Construction Date:** 2010

**Process Description:**

| | |
|---|---|
| Model: | Olympian G35LG |
| Manufacture Date: | 2010 |
| Primary Fuel: | Propane |
| Maximum Continuous Rating: | 0.52 MMBtu/hr (71 HP) |

**Applicable Regulation:**
**401 KAR 60:005, Section 2(2)(eeee)** 40 CFR 60.4230 through 60.4248, Tables 1 through 4 (**Subpart JJJJ**), *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines* applies to owners and operators of spark ignition (SI) internal combustion engines (ICE) manufactured on or after July 1, 2008.

**401 KAR 63:002, Section 2(4)(eeee)**, 40 CFR 63.6580 through 63.6675, Tables 1a through 8 (**Subpart ZZZZ**) *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Interal Combustion Engines* applies to owners and operators of stationary RICE at a major source of HAP emissions.

| **Emission Unit #12 Communication Tower Emergency Generator** |
|---|
| **Comments:**<br>EKPC initially applied for an engine less than 50 HP; however, during the public comment period for the renewal permit, V-18-027, EKPC comments, "Per EKPC records, the horsepower is 54 hp unloaded and 71 hp loaded." Therefore, the Division uses 71 HP as the maximum. |

**Emission Unit #13 Fire Pump Engine**

| **Emission Unit #13 Emergency Fire Pump Engine** |
|---|
| **Initial Construction Date:** 1978 |
| **Process Description:**<br>Model: Scania F674DSJF<br>Construction Date: 1978<br>Primary Fuel: No. 2 Diesel Fuel<br>Maximum Continuous Rating: 2.02 MMBtu/hr |
| **Applicable Regulation:**<br>**401 KAR 63:002, Section 2(4)(eeee)**, 40 CFR 63.6580 through 63.6675, Tables 1a through 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* applies to stationary RICE at a major or area source of HAP emissions. |
| **Comments:**<br>This emission unit is not subject to **401 KAR 60:005, Section 2(2)(dddd),** 40 CFR 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* because the unit was constructed prior to the applicability dates defined in 40 CFR 60.4200(a). |

**Emission Unit #17 NG-Fired Dew Point Heater No. 1**
**Emission Unit #20 CCGT NG-Fired Auxiliary Boiler**
**Emission Unit #23 NG-Fired Dew Point Heater No. 2**

**Emission Unit #24 NG-Fired Dew Point Heater No. 3**

| Emission Unit #17 NG-Fired Dew Point Heater No. 1<br>Emission Unit #20 CCGT NG-Fired Auxiliary Boiler<br>Emission Unit #23 NG-Fired Dew Point Heater No. 2<br>Emission Unit #24 NG-Fired Dew Point Heater No. 3 | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | 0.0019 lb/MMBtu | 401 KAR 51:017 (BACT) | 3.47 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| | 0.10 lb/MMBtu | 401 KAR 59:015, Section 4(1)(b) | 3.47 lb/MMBtu; AP-42 Table 1.4-2 | Compliance is assumed while burning natural gas* |
| | 20% Opacity | 401 KAR 59:015, Section 4(2) | N/A | Compliance is assumed while burning natural gas* |
| $PM_{10}$/ $PM_{2.5}$ | 0.0034 lb/MMBtu | 401 KAR 51:017 (BACT) | 3.47 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| $SO_2$ | 0.80 lb/MMBtu | 401 KAR 59:015, Section 5(1)(b)1. | 1.42 lb/MMBtu; EKPC Requirement | Compliance is assumed while burning natural gas* |
| $NO_X$ | EU 17, 23, 24: 0.05 lb/MMBtu<br><br>EU 20: 0.011 lb/MMBtu | 401 KAR 51:017 (BACT) | EU 17, 23, 24: 50 lb/MMBtu; AP-42 Table 1.4-1<br><br>EU 20: 12.12 lb/MMBtu; Vendor Guarantee | EU 17, 23, 24: Good combustion and operations practices<br><br>EU 20: Initial performance test; monitoring, recordkeeping, and reporting |
| CO | EU 17, 23, 24: 0.082 lb/MMBtu<br><br>EU 20: 0.003 lb/MMBtu | 401 KAR 51:017 (BACT) | EU 17, 23, 24: 84 lb/MMBtu; AP-42 Table 1.4-1<br><br>EU 20: 3.35 lb/MMBtu; Vendor Guarantee | EU 17, 23, 24: Good combustion and operations practices<br><br>EU 20: Initial performance test; monitoring, recordkeeping, and reporting |
| VOC | 0.0054 lb/MMBtu | 401 KAR 51:017 (BACT) | 5.5 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| $CO_2e$ | 117.1 lb/MMBtu | 401 KAR 51:017 (BACT) | N/A | Good combustion and operations practices |

**Proposed Construction Date:** Listed by emission unit:
EU 17, 20, 23, 24 – September 2026

**Emission Unit #17 NG-Fired Dew Point Heater No. 1**
**Emission Unit #20 CCGT NG-Fired Auxiliary Boiler**
**Emission Unit #23 NG-Fired Dew Point Heater No. 2**
**Emission Unit #24 NG-Fired Dew Point Heater No. 3**

**Process Description:**

EU 17:

Preheater (dewpoint heater) used to heat the natural gas that will be burned by C2 "Unit 2 Co-Firing" (EU 2n, process ID 3). The natural gas must be heated above the dew point of any natural gas constituent before firing in the boiler.

| | |
|---|---|
| Description: | Dew Point Heater No. 1 |
| Primary Fuel: | Natural Gas |
| Maximum Rated Capacity: | 11.65 MMBtu/hr |
| Control Devices: | Low $NO_X$ Burners |

EU 20:

Natural gas auxiliary boiler supporting EUs 18 & 19.

| | |
|---|---|
| Description: | NG-Fired Auxiliary Boiler |
| Primary Fuel: | Natural Gas |
| Maximum Rated Capacity: | 99 MMBtu/hr |
| Control Devices: | Ultra Low $NO_X$ Burners, Oxidation Catalyst |

EU 23 and 24:

Two preheaters (dewpoint heaters) used to heat the natural gas that will be burned by "Units 3 and 4" (EUs 18 and 19). The natural gas must be heated above the dew point of any natural gas constituent before firing in the turbines.

| | |
|---|---|
| Description: | Dew Point Heater No. 2 |
| Primary Fuel: | Natural Gas |
| Maximum Rated Capacity: | 9.13 MMBtu/hr |
| Control Devices: | Low $NO_X$ Burners |

| | |
|---|---|
| Description: | Dew Point Heater No. 3 |
| Primary Fuel: | Natural Gas |
| Maximum Rated Capacity: | 9.13 MMBtu/hr |
| Control Devices: | Low $NO_X$ Burners |

**Applicable Regulations:**

**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 59:015**, *New indirect heat exchangers*, is applicable to indirect heat exchangers having a heat input capacity greater than one (1) million BTU per hour (MMBtu/hr) commenced on or after April 9, 1972.

**401 KAR 60:005, Section 2(2)(d),** 40 C.F.R. 60.40c through 60.48c (Subpart Dc), *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* is applicable to each steam generating unit for which construction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h))

| **Emission Unit #17 NG-Fired Dew Point Heater No. 1**<br>**Emission Unit #20 CCGT NG-Fired Auxiliary Boiler**<br>**Emission Unit #23 NG-Fired Dew Point Heater No. 2**<br>**Emission Unit #24 NG-Fired Dew Point Heater No. 3** |
|---|
| or less, but greater than or equal to 2.9 MW (10 MMBtu/h).<br><br>**401 KAR 63:002, Section 2(4)(iiii)**, 40 CFR 63.7480 through 63.7575, Tables 1 through 13 (Subpart DDDDD), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* is applicable to each industrial, commercial, or institutional boiler or process heater as defined in 40 CFR 63.7575 that is located at, or is part of, a major source of HAP, except as specified in 40 CFR 63.7491 [40 CFR 63.7485].<br><br>**Comments:**<br>Most of the emission factors for natural gas combustion are from AP-42 Chapter 1.4.<br><br>The $SO_2$ and $H_2SO_4$ emission factors were derived from conversion equations provided by EKPC.<br>For EU 17, see APE20250001 application P.224.<br>For EU 20, see APE20250001 application P.228.<br>For EUs 23 and 24, see APE20250001 application P.231 and 235.<br><br>The $CO_2$ emission factor is based on data provided in 40 CFR 98 Subpart C, Table C-1 for “Natural Gas”. Methane and Nitrous Oxide emission factors are based on data provided in 40 CFR 98 Subpart C, Table C-2 for “Natural Gas”. |

**Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3**
**Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4**

| Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3<br>Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4 | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $NO_X$ | 2 ppmvd @ 15% $O_2$ [AC] | 401 KAR 51:017 (BACT) | See Table below; EKPC Requirement | $NO_X$ CEMS;<br>Initial performance test;<br>Monitoring, recordkeeping, and reporting |
| | 4.5 ppmvd @ 15% $O_2$ [BC] | | | |
| | 169 TPY [D] | | | |
| | 0.054 kg/MWh-gross (0.12 lb/MWh-gross) [AF] | 40 CFR 60 Subpart KKKKa, Table 1, Item 1 | | |
| | 0.45 kg /MWh-gross (1.0 lb/MWh-gross) [BF] | 40 CFR 60 Subpart KKKKa, Table 1, Item 4 | | |
| CO | 2 ppmvd @ 15% $O_2$ [AC] | 401 KAR 51:017 (BACT) | See Table below; EKPC Requirement | CO CEMS;<br>Monitoring, recordkeeping, and reporting |
| | 2 ppmvd @ 15% $O_2$ [BC] | | | |
| | 2,805 TPY [D] | | | |
| VOC | 1 ppmvd @ 15% $O_2$ [AE] | 401 KAR 51:017 (BACT) | See Table below; EKPC Requirement | Initial performance test;<br>Monitoring, recordkeeping, and reporting;<br>40 CFR 63 Subpart YYYY compliance |
| | 2 ppmvd @ 15% $O_2$ [BE] | | | |
| | 250 TPY [D] | | | |
| PM / $PM_{10}$ / $PM_{2.5}$ | 0.006 lb/MMBtu [AEG] | 401 KAR 51:017 (BACT) | See Table below; EKPC Requirement | Initial performance test;<br>Vendor guarantee sulfur content ≤ 0.5 gr/100scf |
| | 0.014 lb/MMBtu [BEG] | | | Initial performance test;<br>Vendor guarantee sulfur content ≤ 15 ppm |
| | 84.3 TPY [D] | | | Emission Calculation |
| $H_2SO_4$ | Natural Gas Content:<br>0.5 gr S/100scf [A] | 401 KAR 51:017 (BACT) | See Table below; EKPC Requirement | Vendor guarantee sulfur content ≤ 0.5 gr/100scf |
| | Fuel Oil Content:<br>15 ppm total sulfur [B] | | | Vendor guarantee sulfur content ≤ 15 ppm |
| $CO_2$ | 800 lb/MWh-gross [AD] | 401 KAR 51:017 (BACT) | See Table below; 40 CFR | $O_2$ or $CO_2$ CEMS;<br>Fuel quality characteristics |

 

| **Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3<br>Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4** | | | | |
|---|---|---|---|---|
| | 1,250 lb/MWh-gross [BD] | | 98 Subpart C Table C-1 | in a current valid purchase contract, tariff sheet or transportation contract;<br>40 CFR 75 Procedures |
| | Before January 2032:<br>800 to 1,250 lb $CO_2$/MWh-gross [D] | 40 CFR 60 Subpart TTTTa, Table 1, Item 1 | | |
| | After December 2031:<br>100 to 150 lb $CO_2$/MWh-gross [D] | | | |
| $SO_2$ | 110 ng/J (0.90 lb/MWh-gross) energy output<br>OR<br>26 ng/J (0.060 lb/MMBtu) heat input | 40 CFR 60.4330a(a)(1) and (2) and 40 CFR 60.4372a(b) | See Table below; EKPC Requirement | Initial performance test;<br>Fuel quality characteristics in a current valid purchase contract, tariff sheet or transportation contract;<br>Recordkeeping, and reporting |
| Formaldehyde | 91 ppbvd @ 15% $O_2$ except during startup | 40 CFR 63 Subpart YYYY, Table 1, Item 1 | 5.98E-01 lb/MMscf [A]; EKPC Requirement | Performance Testing, Monitoring, Recordkeeping, and Reporting |
| | | | 5.68E-01 lb/Mgal [B]; EKPC Requirement | |
| $CO_2e$ | 1,458,767 TPY [D] | 401 KAR 51:017 (BACT) | N/A; See Comments | Emissions calculation, recordkeeping, and reporting |

| | |
|---|---|
| **A** | When combusting natural gas. |
| **B** | When combusting ultra low sulfur fuel oil (ULSFO). |
| **C** | Based on a 24-hour rolling average (excluding startups and shutdowns). |
| **D** | Based on a 12-month rolling total average (includes startups and shutdowns). |
| **E** | Based on a 3-run average of performance tests. |
| **F** | Additional limits listed under Comments. |
| **G** | Based on a 3-hour average (includes startups and shutdowns). |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
Combined cycle operation consisting of two natural gas-fired lean premix combustion turbines (CT) and one steam turbine (ST) generator. The heat from the combustion gases created by each CT is used in a heat recovery steam generator (HRSG) to produce steam from water in a closed loop system. Each CT is connected to its own HRSG. Electricity is generated from both the CTs and the steam turbine. The CTs are capable of firing ultra low sulfur fuel oil (ULSFO) instead of natural gas to maintain operational flexibility.

**Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3**
**Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4**

| | |
|---|---|
| Manufacturer/Model: | Siemens 5000F |
| Primary Fuel: | Natural Gas |
| Secondary Fuel: | Ultra Low Sulfur Fuel Oil (ULSFO) |
| Maximum Rated Capacity: | |
| When firing Natural Gas – | 2,734 MMBtu/hr each |
| When firing ULSFO – | 2,597 MMBtu/hr each |
| Maximum Power Output: | |
| Steam Turbine Generator – | 745 MWh-net; 785 MWh-nominal-gross† |
| Control Devices: | |
| When firing Natural Gas – | Selective Catalytic Reduction (SCR)<br>Dry Low $NO_X$ Burners (DLN)<br>Oxidation Catalyst (OxCat)<br>Inlet Air Filters (inherent control) |
| When firing ULSFO – | Selective Catalytic Reduction (SCR)<br>Water Injection<br>Oxidation Catalyst (OxCat)<br>Inlet Air Filters (inherent control) |

**Applicable Regulations:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 51:160**, *$NO_X$ requirements for large utility and industrial boilers*; In October 1998, the U.S. EPA finalized the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone", commonly called the $NO_X$ SIP Call. 401 KAR 51:160 was established in response to EPA's $NO_X$ SIP Call and the requirement to implement a NOx Budget Trading Program (NBP). Beginning in 2009, the NBP was effectively replaced by the ozone season $NO_X$ program under the Clean Air Interstate Rule.

**401 KAR 51:210**, *CAIR $NO_X$ annual trading program*
**401 KAR 51:220**, *CAIR $NO_X$ ozone season trading program*
**401 KAR 51:230**, *CAIR $SO_2$ trading program*
On May 12, 2005, the U.S. EPA published the Clean Air Interstate Rule (CAIR). CAIR requires states to reduce emissions of nitrogen oxides and sulfur dioxide that contribute significantly to nonattainment and maintenance problems in downwind states with respect to the national ambient air quality standards for fine particulate matter ($PM_{2.5}$) and 8-hour ozone. Kentucky's regulations are codified in 401 KAR 51:210, CAIR $NO_X$ annual trading program, 401 KAR 51:220, CAIR $NO_X$ ozone season trading program, and 401 51:230, CAIR $SO_2$ trading program.

**401 KAR 51:240**, *Cross-State Air Pollution Rule (CSAPR) $NO_X$ annual trading program*
**401 KAR 51:250**, *Cross-State Air Pollution Rule (CSAPR) $NO_X$ ozone season group 2 trading program*

**Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3**
**Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4**

**401 KAR 51:260**, *Cross-State Air Pollution Rule (CSAPR) $SO_2$ group 1 trading program*
These regulations collectively make up the requirements commonly referred to as the Cross-State Air Pollution Rule (CSAPR). The requirements of CSAPR apply to stationary, fossil-fuel-fired boilers serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25MWe producing electricity for sale.

**401 KAR 52:060**, *Acid rain permits* is applicable to affected sources and units as set forth under 40 CFR 72.6 and incorporates by reference 40 CFR Parts 72 to 78.

**40 CFR 60 Subpart KKKKa,** *Standards of Performance for Stationary Combustion Turbines* is applicable to stationary combustion turbines with a base load rating equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after December 13, 2024. Stationary combustion turbines regulated under 40 CFR 60 Subpart KKKKa are exempt from the requirements of 40 CFR 60 Subpart GG and 40 CFR 60 Subpart KKKK. Duct burners are not subject to 40 CFR 60 Subparts D, Da, Db, or Dc (as applicable) if the duct burner is used with a HRSG unit that is part of a combustion turbine that is subject to 40 CFR 60 Subpart KKKKa [40 CFR 60.4305a(a), (b), and (c)].

**401 KAR 60:005, Section 2(2)(wwww),** 40 CFR 60.5508a through 60.5580a, Tables 1 through 3 (**Subpart TTTTa**), *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* is applicable to stationary combustion turbines that commence construction or reconstruction after May 23, 2023 that have a base load rating greater than 260 gigajoules per hour (GJ/hr) (250 MMBtu/hr) of fossil fuel (either alone or in combination with any other fuel) and serve a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system [40 CFR 60.5509a(a)(1) and (2)].

**401 KAR 63:002, Section 2(4)(dddd),** 40 C.F.R. 63.6080 through 63.6175, Tables 1 through 7 (**Subpart YYYY**), *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* is applicable to stationary combustion turbines located at a major source of HAP emissions [40 CFR 63.6085(b)].

**40 CFR Part 75,** *Continuous Emission Monitoring* is applicable to each the unit subject to Acid Rain emission limitations or reduction requirements for $SO_2$ or $NO_X$ [40 CFR 75.2(a)].

**Comments:**
Footnote †:
On June 6th 2026, the Division submitted a list of questions to EKPC regarding EKPC's comments on the draft permit courtesy copy. The Division asked EKPC to provide the maximum gross power output for the combustion turbines, as there are emission limits based off maximum gross or net power output. EKPC responded to the inquiry on June 11th 2026. EKPC stated that the nominal gross power output is 785 MWs and that the value is *"a design value estimated based off of anticipated operating conditions. It could go up or down dependent on actual operating conditions."*.

These units are not equipped with duct burners and therefore 401 KAR 59:015 does not apply.

$NO_X$ emission limits as determined by the applicable size category in Table 1 or 2 to 40 CFR 60, Subpart

**Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3**
**Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4**

KKKKa are listed below. These limits share the same emission factors and compliance demonstration methods as listed for $NO_X$ above.

| Fuel | Utilization Rate / Design Standard | Emission Limitation | Regulatory Basis for Emission Limit or Standard |
|---|---|---|---|
| Natural Gas | Utilization rate ≤ 45%; Design efficiency ≥ 38% | 0.38 kg/MWh-gross (0.83 lb/MWh-gross) | 40 CFR 60 Subpart KKKKa, Table 1, Item 2 |
| Natural Gas | Mass-based 4-hour $NO_X$ emission standard | 0.38 kg /MW-rated output (0.83 lb/MW-rated output) | 40 CFR 60 Subpart KKKKa, Table 2, Item 1 |
| Fuel Oil | Mass-based 4-hour $NO_X$ emission standard | 0.82 kg /MW-rated output (1.8 lb/MW-rated output) | 40 CFR 60 Subpart KKKKa, Table 2, Item 2 |

The following table lists the emission factors utilized to calculate potential to emit (PTE) for the combustion turbines. Since EUs 18 and 19 are identical turbines, the emission factors apply to both units.

| Operating Mode | $NO_X$ | CO | VOC | $PM/PM_{10}/PM_{2.5}$ | $H_2SO_4$ | $CO_2$ | $SO_2$ | Units |
|---|---|---|---|---|---|---|---|---|
| **Natural Gas** | | | | | | | | |
| Steady State* | 57.64 | 9.35 | 1.91 | 6.49 | 2.18 | 123,995 | 1.42 | lb/MMscf |
| Cold Startup | 321 | 10,799 | 928 | 17 | 1.3 | 210,275 | 3.7 | lb/each |
| Warm Startup | 175 | 5,328 | 462 | 10 | 0.8 | 131,762 | 2.2 | |
| Hot Startup | 110 | 2,896 | 253 | 7 | 0.5 | 96,867 | 1.5 | |
| Shutdown | 56 | 1,011 | 64 | 3 | 0.2 | 66,924 | 0.7 | |
| **Ultra Low Sulfur Fuel Oil (ULSFO)** | | | | | | | | |
| Steady State* | 13.14 | 1.27 | 5.23E-01 | 1.93 | 3.16E-01 | 22,207 | 2.06E-01 | lb/Mgal |
| Cold Startup | 685 | 21,348 | 2,431 | 38 | 1.4 | 305,831 | 4.1 | lb/each |
| Warm Startup | 436 | 12,393 | 1,406 | 27 | 1 | 204,865 | 2.9 | |
| Hot Startup | 241 | 6,423 | 722 | 19 | 0.7 | 137,555 | 2 | |
| Shutdown | 101 | 1,299 | 136 | 9 | 1 | 84,465 | 1 | |

* Does not account for control devices.

Emission factors were determined from manufacturer's data, AP-42 data, and PTE calculations provided by EKPC Cooper. See the following documents listed under APE20250001:
*"Cooper Project PSD Application 2025-0127"* P.188-208
*"Cooper Project NOD Response (2025-0905)"* P.19, 25-45
*"EKPC_Cooper_Project_App_Supplement_Compiled_2026-0108"* P.13-15, 53-73

$NO_X$, CO, and VOC emission factors were calculated using the max lb/hr emission rate from the vendor specification, the max heat input capacity for each fuel, and the site-specific higher heating value (HHV)

**Emission Unit #18 Combined Cycle Gas Turbine (CCGT) Unit 3**
**Emission Unit #19 Combined Cycle Gas Turbine (CCGT) Unit 4**

for each fuel (*"Cooper Project PSD Application 2025-0127"* P.191).

$PM/PM_{10}/PM_{2.5}$ emission factors were calculated using max lb/hr emission rate from the vendor specification, the max heat input capacity for each fuel, and the site-specific HHV for each fuel (*"Cooper Project PSD Application 2025-0127"* P.192). EKPC stated that "*all PM can be assumed to be less than 2.5 µm in mean diameter (i.e., $PM = PM_{10} = PM_{2.5}$)*" (P.192). The Division used the highest PM emission factor for all three entries (i.e., $PM = PM_{10} = PM_{2.5}$).

$H_2SO_4$ emission factors were calculated using max lb/hr emission rate from the vendor specification, the max heat input capacity for each fuel, and the site-specific HHV for each fuel (*"Cooper Project PSD Application 2025-0127"* P.192).

$CO_2$ emission factors were calculated using the emission factors from 40 CFR 98 Subpart C, Table C-1 for each fuel and the site-specific heating value for each fuel (*"Cooper Project PSD Application 2025-0127"* P.193).

$SO_2$ emission factors were calculated using the sulfur concentration of each fuel, the max heat input capacity for each fuel, the HHV for each fuel, and the assumption that 100% of S is converted to $SO_2$ for the purposes of calculating PTE (*"Cooper Project PSD Application 2025-0127"* P.192).

EKPC presented the three "worse-case" operating scenarios for the CTs for the purpose of calculating PTE. The three operating scenarios are outlined as follows:
Scenario 1 – 7,680 hr/yr steady-state Natural Gas firing + 1,080 hr/yr steady-state ULSFO firing.
Scenario 2 – 4,189 hr/yr steady-state Natural Gas firing + 853 hr/yr steady-state ULSFO firing + Startup and Shutdown events.
Scenario 3 – 8,760 hr/yr steady-state Natural Gas firing.

The Division performed emission calculations for all three operating scenarios. The highest PTE out of the scenarios was chosen for estimating emissions. The highest was Scenario 1; 7,680 hr/yr N.G. firing + 1,080 hr/yr ULSFO firing.

Currently, *utilization rate* is not defined in the codified regulation for 40 CFR 60, Subpart KKKKa. However, under the final rule published in the federal register on January 15, 2026, the terms *annual capacity factor* and *utilization rate* are used interchangeably. Since *annual capacity factor* is defined in the codified version of the regulation but is not used anywhere else in the codified version of the regulation, the definition of *utilization rate* has been added to the permit using the definition of *annual capacity factor*.

There is no emission factor for $CO_2e$ (or "$CO_2$ Equivalent") as it is a sum of TPY values for greenhouse gas pollutants. $CO_2e$ in tons per year, is calculated using the most recent Global Warming Potential (GWP) values found at 40 CFR 98, Subpart A, Table A-1.

The GWP value for $CO_2$ remains at 1.
The GWP value for $N_2O$ is 265
The GWP value for Methane ($CH_4$) is 28.
$CO_2e = (CO_2 \times 1) + (N_2O \times 265) + (CH_4 \times 28)$

**Emission Unit #21 Emergency Diesel Generator (12.5 MMBtu/hr)**

| Emission Unit #21 CCGT Emergency Diesel Generator (12.5 MMBtu/hr) | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $NO_X$ + NMHC | 4.8 g/HP-hr | 40 CFR 4205(b); 401 KAR 51:017 (BACT) | 198.87 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| CO | 2.6 g/HP-hr | 40 CFR 4205(b); 401 KAR 51:017 (BACT) | 111.95 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| $PM/PM_{10}/PM_{2.5}$ | 0.15 g/HP-hr | 40 CFR 4205(b); 401 KAR 51:017 (BACT) | 6.39 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| $CO_2e$ | 163 lb/MMBtu | 401 KAR 51:017 (BACT) | N/A | Good Combustion Operating Practices |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
One diesel fueled emergency electrical generator, nominal 1,250 kW (2,200 bhp). The generator is a compression ignition engine running on Diesel fuel.

| | |
|---|---|
| Rated Output: | 1,250 kW (2,220 HP), 1,750 RPM |
| Model: | TBD |
| Rated Capacity: | 12.5 MMBtu/hr (2,200 bhp) |
| Fuel Rate: | 113 gal/hr |
| Fuel: | Diesel |
| Cylinder # and Config.: | 16 cylinders (V-16), 4-stroke |
| Total Displacement: | 78 L |

**Applicable Regulations:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 60:005, Section 2(2)(dddd),** 40 CFR 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* is applicable to stationary compression ignition (CI) emergency generator engines for which construction is commenced after July 11, 2005 and which are manufactured after April 1, 2006 (or July 1, 2006 for fire pump engines).

**401 KAR 63:002, Section 2(4)(eeee)**, 40 CFR 63.6580 through 63.6675, Tables 1a through 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* is applicable to stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. The permittee shall meet the requirements of 40 CFR Part 63 by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements apply for the engine under 40 CFR Part 63 except for the initial notification requirements of 40 CFR 63.6645(f) [40 CFR 63.6590(b)(1) and (b)(1)(i)].

| **Emission Unit #21 CCGT Emergency Diesel Generator (12.5 MMBtu/hr)** |
|---|
| **Comments:**<br>PTE calculations are based on 500 hours per year of operation.<br>The permittee shall utilize ultra low sulfur diesel with a maximum sulfur content of 0.0015 weight percent (15 ppmw) sulfur.<br>The facility must monitor and maintain records of fuel usage on a monthly basis.<br>Part of the required vendor data was provided with the NOD Response (See APE20250001 *"Cooper Project NOD Response (2025-0905)"*), P.47-53. EKPC stated in the NOD Response that "The specific vendors and model numbers of the engines planned for installation will not be known until farther in the project schedule" (P.53). |

**Emission Unit #22 Diesel Fire Pump Engine**

| **Emission Unit #22 CCGT Emergency Fire Pump Engine** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $NO_X$ + NMHC | 3.0 g/HP-hr | 40 CFR 60.4205(c); 401 KAR 51:017 (BACT) | 118.35 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| CO | 2.6 g/HP-hr | 40 CFR 60.4205(c); 401 KAR 51:017 (BACT) | 111.52 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| $PM/PM_{10}/PM_{2.5}$ | 0.15 g/HP-hr | 40 CFR 60.4205(c); 401 KAR 51:017 (BACT) | 6.39 lb/Mgal; EKPC Requirement | Purchasing a certified engine |
| $CO_2e$ | 163 lb/MMBtu | 401 KAR 51:017 (BACT) | N/A | Good Combustion Operating Practices |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
One diesel fueled emergency fire pump engine, nominal 310 HP (231 kW). The fire pump is a compression ignition engine running on Diesel fuel.

| | |
|---|---|
| Rated Output: | 310 HP (231 kW), 2,100 RPM |
| Model: | TBD |
| Rated Capacity: | 0.788 MMBtu/hr (310 bhp) |
| Fuel Rate: | 15.9 gal/hr |
| Fuel: | Diesel |
| Cylinder # and Config.: | 6 cylinders (In-Line), 4-stroke |
| Total Displacement: | 12.5 L |

**Applicable Regulations:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

| **Emission Unit #22 CCGT Emergency Fire Pump Engine** |
|---|
| **401 KAR 60:005, Section 2(2)(dddd),** 40 CFR 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* is applicable to stationary compression ignition (CI) emergency generator engines for which construction is commenced after July 11, 2005 and which are manufactured after April 1, 2006 (or July 1, 2006 for fire pump engines).<br>**401 KAR 63:002, Section 2(4)(eeee)**, 40 CFR 63.6580 through 63.6675, Tables 1a through 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* is applicable to stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. The permittee shall meet the requirements of 40 CFR Part 63 by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements apply for the engine under 40 CFR Part 63 [40 CFR 63.6590(c)(6)].<br>**Comments:**<br>PTE calculations are based on 500 hours per year of operation.<br>The permittee shall utilize ultra low sulfur diesel with a maximum sulfur content of 0.0015 weight percent (15 ppmw) sulfur.<br>The facility must monitor and maintain records of fuel usage on a monthly basis.<br>Part of the required vendor data was provided with the NOD Response (See APE20250001 *"Cooper Project NOD Response (2025-0905)"*), P.47-53. EKPC stated in the NOD Response that "The specific vendors and model numbers of the engines planned for installation will not be known until farther in the project schedule" (P.53). |

**<u>Emission Unit #25 CCGT Cooling Tower (Mechanical Draft Cooling Tower, 9 Cells)</u>**

| **Emission Unit #25 CCGT 9-Cell Mechanical Draft Cooling Tower** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | $P \leq 0.5$ ton/hr<br>$E = 2.34$ lb/hr<br>$0.5 < P \leq 30$<br>$E = 3.59 \times P^{0.62}$<br>$P > 30$<br>$E = 17.31 \times P^{0.16}$ | 401 KAR 59:010, Section 3(2) | 1.04E-01 lb/MMgal; Application – APE20250001 | Compliance is assumed while control equipment is operating |
| | 20% Opacity | 401 KAR 59:010, Section 3(1)(a) | N/A | Compliance is assumed while control equipment is operating |
| PM | 1.04 lb/hr | 401 KAR 51:017 | $1.04 \times 10^{-1}$ lb/MMgal; Application – APE20250001 | Operate as designed |
| | 4.54 tpy | 401 KAR 51:017 | | Operate as designed |
| $PM_{10}$ | 0.13 lb/hr | 401 KAR 51:017 | $1.34 \times 10^{-2}$ lb/MMgal; Application – APE20250001 | Operate as designed |
| | 0.59 tpy | 401 KAR 51:017 | | Operate as designed |
| $PM_{2.5}$ | $1.3 \times 10^{-3}$ lb/hr | 401 KAR 51:017 | $1.26 \times 10^{-4}$ lb/MMgal; | Operate as designed |

| **Emission Unit #25 CCGT 9-Cell Mechanical Draft Cooling Tower** | | | | |
|---|---|---|---|---|
| | $5.5x10^{-3}$ tpy | 401 KAR 51:017 | Application – APE20250001 | Operate as designed |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
One Mechanical Draft Cooling Tower with 9 cells. The cooling tower provides cooling for the condensing steam turbine exhaust and the plant auxiliary equipment. It serves the design heat capacity with a circulating cooling water flow rate of 165,800 gallons per minute. The drift rate will not exceed 0.0005 percent according to design specification. Drift eliminators are installed to reduce particulate emissions. Additionally, the design specification allows no more than 2,500 ppm total dissolved solids (TDS) in the recirculating water which reduces particulate emissions.

| | |
|---|---|
| Design circulating water flow rate: | 165,800 gal/min |
| Total Dissolved Solids (TDS): | 2,500 ppm |
| Control Device: | Drift Eliminators |
| Drift percentage: | 0.0005% |

**Applicable Regulations:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 59:010**, *New process operations* is applicable to each affected facility, associated with a process operation, which is not subject to another emission standard with respect to particulates, commenced on or after July 2, 1975.

**Precluded Regulation:**
**401 KAR 63:002, Section 2(4)(j)**, 40 CFR 63.400 through 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers* applies to industrial process cooling towers operated with chromium-based water treatment chemicals. This unit is not operated with chromium-based water treatment chemicals.

**Comments:**
Drift eliminators certified by the manufacturer to have 0.0005% or less drift loss.

Emissions from the cooling tower are determined from the circulating cooling water rate of 165,800 gallons per minute, design drift efficiency of 0.0005%, the total-solids content of the cooling water of 2,500 ppm, and the density of the recirculating water of 8.34. Annual emissions are based on continuous operation of the cooling towers.

**Emission Unit #26A Fuel Oil Storage Tank #1**
**Emission Unit #26B Fuel Oil Storage Tank #2**
**Emission Unit #27 Emergency Generator Diesel Storage Tank**
**Emission Unit #28 Fire Pump Diesel Storage Tank**

**Emission Unit #26A Fuel Oil Storage Tank #1**
**Emission Unit #26B Fuel Oil Storage Tank #2**
**Emission Unit #27 Emergency Generator Diesel Storage Tank**
**Emission Unit #28 Fire Pump Diesel Storage Tank**

**Initial Construction Date:** Proposed September 2026

**Process Description:**
EU 26A – 1.66 MMgal tank that stores ultra low sulfur fuel oil (ULSFO) for the CTs (EUs 18 and 19).
EU 26B – 1.66 MMgal tank that stores ultra low sulfur fuel oil (ULSFO) for the CTs (EUs 18 and 19).
EU 27 – 1,000 gallon diesel storage tank for the emergency generator engine (EU 21).
EU 28 – 350 gallon diesel storage tank for the fire pump engine (EU 22).

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**State-Origin Requirement:**
**401 KAR 63:020**, *Potentially hazardous matter or toxic substances*, is applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.

**Comments:**
The maximum true vapor pressure of the ULSFO in each tank (EU 26A and 26B) is less than 0.25 psia and therefore 40 CFR 60 Subpart Kc does not apply (See EKPC original application P.156).

Based on actual historical EKPC usage rates, EKPC provided an estimated annual throughput for each tank (EKPC application P.156):

| Emission Unit | Throughput |
|---|---|
| 26A | 21,280,800 gal/yr |
| 26B | 21,280,800 gal/yr |
| 27 | 45,888 gal/yr |
| 28 | 7,966 gal/yr |

These emission units are not subject to **401 KAR 59:050,** *New storage vessels for petroleum liquids* because "Petroleum liquids" as defined in 401 KAR 59:050, Section 2 does not mean Number 2 through Number 6 fuel oils.

These emission units are not subject to **40 CFR 60 Subpart Kc,** *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023* because the maximum true vapor pressure of the tanks is less than 0.5 psia (3.4 kPa) [40 CFR 60.110c(c)(1)].

**Emission Unit #29A Natural Gas-Fired HVAC Heaters**

| Emission Unit #29A Natural Gas-Fired HVAC Heaters | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| PM | 0.10 lb/MMBtu | 401 KAR 59:015, Section 4(1)(b) | 3.47 lb/MMBtu; AP-42 Table 1.4-2 | Compliance is assumed while burning natural gas* |
| PM | 20% Opacity | 401 KAR 59:015, Section 4(2) | N/A | Compliance is assumed while burning natural gas* |
| PM<br>$PM_{10}$<br>$PM_{2.5}$ | 0.003 lb/MMBtu | 401 KAR 51:017 (BACT) | 3.47 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| $SO_2$ | 0.80 lb/MMBtu | 401 KAR 59:015, Section 5(1)(b)1. | 1.42 lb/MMBtu; EKPC Requirement | Compliance is assumed while burning natural gas* |
| $NO_X$ | 0.1 lb/MMBtu | 401 KAR 51:017 (BACT) | 100 lb/MMBtu; AP-42 Table 1.4-1 | Good combustion and operations practices |
| CO | 0.082 lb/MMBtu | 401 KAR 51:017 (BACT) | 84 lb/MMBtu; AP-42 Table 1.4-1 | Good combustion and operations practices |
| VOC | 0.005 lb/MMBtu | 401 KAR 51:017 (BACT) | 5.5 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| $CO_2e$ | 117.1 lb/MMBtu | 401 KAR 51:017 (BACT) | N/A | Good combustion and operations practices |

* The permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf.

**Initial Construction Date:** Proposed September 2026

**Process Description:**
Natural gas-fired HVAC heaters for heating buildings. 3 indirect-fired HVAC heaters with a heat input capacity of 3.9 MMBtu/hr each.

| | |
|---|---|
| Description: | HVAC Heaters > 1 MMBtu/hr |
| Primary Fuel: | Natural Gas |
| Maximum Rated Capacity: | 11.7 MMBtu/hr total |
| Control Devices: | N/A |

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 59:015**, *New indirect heat exchangers*, is applicable to indirect heat exchangers having a heat input capacity greater than one (1) million BTU per hour (MMBtu/hr) commenced on or after April 9, 1972.

| Emission Unit #29A Natural Gas-Fired HVAC Heaters |
|---|
| **State-Origin Requirement:**<br>**401 KAR 63:020**, *Potentially hazardous matter or toxic substances*, is applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.<br><br>**Comments:**<br>EKPC originally planned on installing 7 HVAC heaters at 5.5 MMBtu/hr each but changed their plans in the Supplement Application P.20<br>(See APE20250001 *"EKPC_Cooper_Project_App_Supplement_Compiled_2026-0108"*). |

**Emission Unit #29B Small Natural Gas-Fired HVAC Heaters**
**Emission Unit #29C Small Natural Gas-Fired HVAC Heaters**

| Emission Unit #29B Small Natural Gas-Fired HVAC Heaters<br>Emission Unit #29C Small Natural Gas-Fired HVAC Heaters | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $NO_X$ | 0.1 lb/MMBtu | 401 KAR 51:017 (BACT) | 100 lb/MMBtu; AP-42 Table 1.4-1 | Good combustion and operations practices |
| CO | 0.082 lb/MMBtu | 401 KAR 51:017 (BACT) | 84 lb/MMBtu; AP-42 Table 1.4-1 | Good combustion and operations practices |
| VOC | 0.005 lb/MMBtu | 401 KAR 51:017 (BACT) | 5.5 lb/MMBtu; AP-42 Table 1.4-2 | Good combustion and operations practices |
| $CO_2e$ | 117.1 lb/MMBtu | 401 KAR 51:017 (BACT) | N/A | Good combustion and operations practices |

**Initial Construction Date:**
EU 29B and 29C – Proposed September 2026

**Process Description:**
Small natural gas-fired HVAC heaters for heating buildings.
EU 29B: 4 indirect-fired HVAC heaters with a heat input capacity of 0.06 MMBtu/hr each (0.24 MMBtu/hr total).
EU 29C: 3 indirect-fired HVAC heaters with a heat input capacity of 0.36 MMBtu/hr each (1.08 MMBtu/hr total).
All heaters are natural gas fueled.
No control devices are present.

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**State-Origin Requirement:**
**401 KAR 63:020**, *Potentially hazardous matter or toxic substances*, is applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances, provided such emissions are

| Emission Unit #29B Small Natural Gas-Fired HVAC Heaters<br>Emission Unit #29C Small Natural Gas-Fired HVAC Heaters |
|---|
| not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.<br><br>**Comments:**<br>EKPC originally planned on installing 14 HVAC heaters at 0.061 MMBtu/hr each but changed their plans in the Supplement Application P.20 (See APE20250001 *"EKPC_Cooper_Project_App_Supplement_Compiled_2026-0108"*). The heaters are grouped by size in the supplement application. The four 0.06 MMBtu/hr heaters are considered part of "EU 29B" and the three 0.36 MMBtu/hr heaters are considered part of "EU 29C". The Division accepted the groupings for the HVAC heaters under 1 MMBtu/hr and named the units EU 29B and EU 29C. |

**<u>Emission Unit #30 3 Turbine Circuit Breakers</u>**
**<u>Emission Unit #31 12 Switchyard/Station Circuit Breakers</u>**

| **Emission Unit #30 3 Turbine Circuit Breakers<br>Emission Unit #31 12 Switchyard/Station Circuit Breakers** | | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| GHGs ($SF_6$) | EU 30 | Annual leakage rate shall not exceed 0.5 percent by weight | 401 KAR 50:017 | 0.15 lb/circuit breaker | Recordkeeping of AVO inspections and leak detection system |
| | EU 31 | | | 0.29 lb/circuit breaker | |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
EU 30 – Three (3) 20 kV Turbine Circuit Breakers. Each unit contains a 30 lb sulfur hexafluoride ($SF_6$) breaker.
EU 31 – Twelve (12) 170 kV Switchyard/Station Circuit Breakers. Each unit contains a 58 lb sulfur hexafluoride ($SF_6$) breaker.
Control Device: N/A
Maximum allowable $SF_6$ leak rate: 0.5%

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**Comments:**
The annual leakage rate of $SF_6$ shall not exceed 0.5 percent by weight.
The permittee shall install and operate a leak detection system for $SF_6$ as BACT for the circuit breakers.
$SF_6$ Global Warming Potential used to calculate PTE is 23,500 lb $CO_2e$ / lb $SF_6$.
PTE was calculated based upon 8,760 hours of operation.

Emissions are calculated by multiplying the total number of circuit breakers (15), weight of the $SF_6$ in each circuit breaker (30lbs for the Turbine Circuit Breakers, 58 lbs for the Switchyard/Station Circuit Breakers), and the leak rate weight percent emission limitation of not more than 0.5% leakage. The GWP of $SF_6$ used was 23,500 from 40 CFR Part 98 Subpart A Table A-1, as published January 1, 2025.

**Emission Unit #32 CCGT Haul Roads**

| **Emission Unit #32 CCGT Haul Roads** | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $PM/PM_{10}/PM_{2.5}$ | No discharge of visible fugitive dust emissions beyond property line for more than 5 minutes during any 60-minute observation period or more than 20 minutes during any 24-hour period | 401 KAR 63:010, Section 3(2) | See **Comments** | Take reasonable precautions to prevent particulate matter from becoming airborne |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
New Plant Paved Roadways used as Haul Roads constructed with the CCGT Project.
Control Device: Wet suppression as needed

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 63:010**, *Fugitive Emissions*, is applicable to each affected facility (road) that emits or could emit fugitive emissions not elsewhere subject to an opacity standard within 401 KAR Chapters 50 through 68.

**Comments:**
Emissions were calculated using AP-42 Chapter 13.2.1, Equation 1 (page 4) Paved Roads Equation. A silt loading factor of 0.6 was used (roads with < 500 vehicles per day). Mean vehicle weights and miles traveled as supplied by the facility as well as the calculated emission factors are shown below:

| **Truck Type** | **Mean Vehicle Weight (tons/vehicle)** | **Total Combined Vehicle Miles Traveled (VMT/yr)** | **Emission Factors (lb/VMT)** | | |
|---|---|---|---|---|---|
| | | | PM | $PM_{10}$ | $PM_{2.5}$ |
| 19% Aqueous $NH_3$ Delivery | 24.14 | 170.6 | 0.177 | 0.035 | 0.008 |
| ULSFO Delivery | 34.38 | 5,835.3 | 0.255 | 0.051 | 0.012 |
| Water Chemical Delivery | 25.91 | 91.74 | 0.191 | 0.038 | 0.009 |
| Cooling Tower Chemical Delivery | 26.01 | 12.78 | 0.191 | 0.038 | 0.009 |

**Emission Unit #33 Natural Gas Piping Fugitives**

**Emission Unit #33 Natural Gas Piping Fugitives**

**Initial Construction Date:** Proposed September 2026

**Process Description:**
New natural gas piping components to be installed as part of the CCGT construction and Unit 2 co-firing modification projects.
Points in the Natural Gas pipeline and receiving equipment that may have fugitive emissions.
Control Device: N/A

| Piping Component Type: | | | Component Count | | |
|---|---|---|---|---|---|
| | | | CCGT: | Unit 2 Co-Fire: | Total Components: |
| Valves | 200 | 470 | 200 | 470 | 670 |
| Relief Valves | 16 | 5 | 16 | 5 | 21 |
| Flanges | 280 | 1,700 | 280 | 1700 | 1980 |
| Sampling Connections | 2 | 0 | 2 | 0 | 2 |

NOTE - The natural gas fugitive piping component count listed above reflects an estimated count of the equipment as of the date of issuance of this permit but is not intended to limit the permittee to the exact numbers specified. The permittee may add or remove natural gas fugitive piping components without a permit revision as long as the equipment continues to comply with the applicable requirements listed below and the changes do not result in a significant increase in potential to emit.

**Applicable Regulations:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].

**401 KAR 63:020**, *Potentially hazardous matter or toxic substances*, is applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.

**Comments:**
Emissions are calculated using the component counts shown above (as supplied by EKPC), component leak rates from EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates Table 2-4, and natural gas composition weight percents provided by EKPC (1.15% VOC content, 0.44% $CO_2$ content, and 85.1% $CH_4$ content) (See Supplement Application APE20250001 *"EKPC_Cooper_Project_App_Supplement_Compiled_2026-0108"* P.100).

**Emission Unit #34 Sulfuric Acid Storage Tank**

| Emission Unit #34 Sulfuric Acid Tank |
|---|
| **Initial Construction Date:** Proposed September 2026<br><br>**Process Description:**<br>3,000 gallon sulfuric acid storage tank for facility-wide usage. The aqueous solution is 93% $H_2SO_4$.<br>Control Device: N/A<br><br>**Applicable Regulation:**<br>**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].<br><br>**Comments:**<br>Emission calculations were performed with TankESP analysis using methodology presented in AP-42 Section 7.1 and sulfuric acid partial pressure data from Perry's Chemical Engineer's Handbook, 8th Edition. See EKPC's original application P.312.<br><br>Tank height = 6.34 ft<br>Tank diameter = 12.69 ft<br>Tank Volume = 401 $ft^3$ (Volume in gallons = 3000 gal (7.48 $ft^3$/gal))<br>Design rate $H_2SO_4$ liquid throughput = 2.28 gal/hr |

**Emission Unit #35 Coal Storage and Handling Operations #2**

| Emission Unit #35 Coal Storage and Handling Operations for Coal Stockpile #2 | | | | |
|---|---|---|---|---|
| **Pollutant** | **Emission Limit or Standard** | **Regulatory Basis for Emission Limit or Standard** | **Emission Factor Used and Basis** | **Compliance Method** |
| $PM/PM_{10}/PM_{2.5}$ | No discharge of visible fugitive dust emissions beyond property line for more than 5 minutes during any 60-minute observation period or more than 20 minutes during any 24-hour period | 401 KAR 63:010, Section 3(2) | See **Comments** | Take reasonable precautions to prevent particulate matter from becoming airborne |

**Initial Construction Date:** Proposed September 2026

**Process Description:**
Truck unloading, coal stockpile, and yard area. Storage capacity of 58,032 tons of coal. The coal pile has two drop points.
Maximum Continuous Rating: 300 tons/hr
Control Device: Water spray/additives to reduce fugitive emissions

**Applicable Regulation:**
**401 KAR 51:017,** *Prevention of significant deterioration of air quality* is applicable to construction of a new major stationary source or a project at an existing major stationary source that commences

| Emission Unit #35 Coal Storage and Handling Operations for Coal Stockpile #2 |
| --- |
| construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407(d)(1)(A)(ii) and (iii) [401 KAR 51:017, Section 1(1)].<br><br>**401 KAR 63:010**, *Fugitive Emissions*, is applicable to each affected facility (road) that emits or could emit fugitive emissions not elsewhere subject to an opacity standard within 401 KAR Chapters 50 through 68.<br><br>**Comments:**<br>EU 35 currently consists of three process IDs: Coal Pile, Dumping, and Unpaved Roads.<br>Emission factors for the coal pile are derived from "EPA Control of Open Fugitive Dust Sources".<br>Emissions factors for the coal dumping are derived from AP-42 Chapter 13.2.4, Equation 1 (page 4) Predictive Emission Factor Equation.<br>Emissions factors for the unpaved haul roads are derived from AP-42 Chapter 13.2.2, Equation 1a (page 4) Unpaved Roads Equation. |

## SECTION 3 – EMISSIONS, LIMITATIONS AND BASIS (CONTINUED)

**Testing Requirements\Results**

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| 18 | SCR, DLN, OxCat, Water Injection | VOC | 401 KAR 51:017 | 3 Runs (Every 5 years) | Methods 25, 25A, 18 or ALT-096 or 320 | NG: 1 ppmvd VOC @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| | | | | | | FO: 2 ppmvd @ 15% $O_2$ | TBD | TBD | | |
| 19 | SCR, DLN, OxCat, Water Injection | VOC | 401 KAR 51:017 | 3 Runs (Every 5 years) | Methods 25, 25A, 18 or ALT-096 or 320 | NG: 1 ppmvd VOC @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| | | | | | | FO: 2 ppmvd @ 15% $O_2$ | TBD | TBD | | |
| 18 | SCR, DLN, OxCat, Water Injection | $PM/PM_{10}/PM_{2.5}$ | 401 KAR 51:017 | 3 Runs (Every 5 years) | Methods 5 or 201 and 202 | NG: 16.76 lb/hr | TBD | TBD | TBD | TBD |
| | | | | | | FO: 36.9 lb/hr | | | | |

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| 19 | SCR, DLN, OxCat, Water Injection | $PM/PM_{10}/PM_{2.5}$ | 401 KAR 51:017 | 3 Runs (Every 5 years) | Methods 5 or 201 and 202 | NG: 16.76 lb/hr | TBD | TBD | TBD | TBD |
| | | | | | | FO: 36.9 lb/hr | TBD | TBD | | |
| 18 | SCR, DLN, OxCat, Water Injection | $NO_X$ | 401 KAR 51:017 | 9 RATA Runs (Initial) | 40 CFR Part 75 | NG: 2 ppmvd @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| | | | | | | FO: 4.5 ppmvd @ 15% $O_2$ | TBD | TBD | | |
| | | | 40 CFR 60.4333a(b) | | | NG: 0.12 lb/MWh-gross | TBD | TBD | | |
| | | | | | | FO: 1.0 lb/MWh-gross | TBD | TBD | | |
| 19 | SCR, DLN, OxCat, Water Injection | $NO_X$ | 401 KAR 51:017 | 9 RATA Runs (Initial) | 40 CFR Part 75 | NG: 2 ppmvd @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| | | | | | | FO: 4.5 ppmvd | TBD | TBD | | |

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | @ 15% $O_2$ | | | | |
| | | | 40 CFR 60.4333a(b) | | | NG: 0.12 lb/MWh-gross | TBD | TBD | | |
| | | | | | | FO: 1.0 lb/MWh-gross | TBD | TBD | | |
| 18 | SCR, DLN, OxCat, Water Injection | Formaldehyde | 40 CFR 63 Subpart YYYY, Table 3, Item a. | 3 Runs (Annual) | Method 320 or ASTM D6348-12e1 | ≤ 91 ppbvd @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| 19 | SCR, DLN, OxCat, Water Injection | Formaldehyde | 40 CFR 63 Subpart YYYY, Table 3, Item a. | 3 Runs (Annual) | Method 320 or ASTM D6348-12e1 | ≤ 91 ppbvd @ 15% $O_2$ | TBD | TBD | TBD | TBD |
| 20 | OxCat, LNBs | $NO_x$ | 401 KAR 51:017 | Initial (Every 5 years) | Method 7E | 0.011 lb/MMBtu | TBD | TBD | TBD | TBD |
| 20 | OxCat, LNBs | CO | 401 KAR 51:017 | Initial (Every 5 years) | Method 7E | 0.003 lb/MMBtu | TBD | TBD | TBD | TBD |

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| Unit 1 | SCR, CFB Scrubber, PJFF | PM | Consent Decree Entered September 24, 2007 | Annual | Method 5 | 0.03 lb/MMBtu | TBD | TBD | CMN20260007 | TBD |
| Unit 2 | SCR, CFB Scrubber, PJFF | | | | | | TBD | TBD | CMN20260006 | TBD |
| Unit 2 | SCR, CFB Scrubber, PJFF | PM | Consent Decree Entered September 24, 2007 | Annual | Method 5 | 0.03 lb/MMBtu | 0.002 lb/MMBtu | 233 MW | CMN20250004 | 11/7/2025 |
| Unit 1 | ESP, CFB Scrubber, PJFF | | | | | | 0.0004 lb/MMBtu | 116.6 MW | CMN20250003 | 9/3/2025 |
| Units 1 & 2 Common Stack | Unit 1: ESP Unit 2: SCR Shared: CFB Scrubber, PJFF | PM | 40 CFR 63, Subpart UUUUU | Annual | Method 5 | 0.03 lb/MMBtu | 0.00194 lb/MMBtu | 319.32 MW | CMN20250002 | 6/11/2025 |
| | | HCl | | | Method 26A | 0.002 lb/MMBtu | 0.000025 lb/MMBtu | 348.21 MW | CMN20250001 | 6/10/2025 |
| Unit 2 | SCR, CFB Scrubber, PJFF | PM | Consent Decree Entered September 24, 2007 | Annual | Method 5 | 0.030 lb/MMBtu | 0.0032 lb/MMBtu | 234 MW | CMN20240003 | 7/26/2024 |
| Unit 1 | ESP, CFB Scrubber, PJFF | | | | | | 0.002 lb/MMBtu | 116 MW | CMN20240002 | 11/05/2024 |
| Unit 1 | ESP | PM | Consent Decree Entered | Annual | Method 5 | 0.030 lb/MMBtu | 0.002 lb/MMBtu | 116 MW | CMN20230004 | 10/03/2023 |

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| Unit 2 | SCR, CFB Scrubber, PJFF | | September 24, 2007 | | | | 0.006 lb/MM Btu | 231 MW | CMN20230003 | 4/28/2023 |
| Units 1 & 2 Commo n Stack | Unit 1: ESP Unit 2: SCR Shared: CFB Scrubber, PJFF | HCl | 40 CFR 63, Subpart UUUUU | Annual | Method 26A | 0.002 lb/MMBtu | 0.00004 lb/MM Btu | 350 MW | CMN20220006 | 6/9/2022 |
| Unit 1 | ESP, CFB Scrubber, PJFF | PM | Consent Decree entered September 24, 2007 | Annual | Method 5 | 0.030 lb/MMBtu | 0.002 lb/MM Btu | 115 MW | CMN20220005 | 10/13/2022 |
| Unit 2 | LNB, SCR, FGD, PJFF | | | | | 0.030 lb/hr | 0.003 lb/hr | 234 MW | CMN20220004 | 6/6/2022 |
| Unit 1 | ESP, CFB Scrubber, PJFF | PM | Consent Decree Entered September 24, 2007 | Annual | Method 5 | 0.030 lb/MMBtu | 0.001 lb/MM btu | 117.2 MW | CMN20210001 | 7/12/2021 |
| Unit 2 | LNB, SCR, FGD, PJFF | | | | | 0.030 lb/MMBtu | 0.001 lb/MM Btu | 237 MW | CMN20200010 | 7/30/2021 |
| Unit 2 | LNB, SCR, FGD, PJFF | PM | Consent Decree entered September 24, 2007 | Annual | Method 5 | 0.03 lb/MMBtu | 0.001 lb/MM Btu | 233.0 MW | CMN20200005 | 7/17/2020 |
| Unit 1 | ESP, LNB, Dry FGD, PJFF | | | | | | 0.001 lb/MM Btu | 117.7 MW | CMN20200004 | 7/30/2020 |
| 1 | ESP, CFB Scrubber, and Fabric | PM | Consent Decree entered on | Annual | Method 5 | 0.03 lb/MMBtu | 0.00388 lb/MM Btu | 118 MW | CMN20190011 | 8/5/2019 |

| Emission Unit(s) | Control Device | Parameter | Regulatory Basis | Frequency | Test Method | Permit Limit | Test Result | Thruput and Operating Parameter(s) Established During Test | Activity Graybar | Date of last Compliance Testing |
|---|---|---|---|---|---|---|---|---|---|---|
| | Filter | | September 24, 2007. Paragraph 84 | | | | | | | |
| 2 | ESP, LNB, FGD, SCR, PJFF, FuelSolv | | | | | | 0.00409 lb/MM Btu | 235 MW | CMN20190010 | 8/5/2019 |
| Units 1 & 2 Shared Stack | Unit 1: ESP, LNB, MerControl Unit 2: LNB, SCR, FuelSolv, Shared: DFGD, PJFF | HCl | 40 CFR 63, Subpart UUUUU | Annual | Method 26A | 0.002 lb/MMbtu | 0.00003 lb/MM btu | 353 MW | CMN20190002 | 6/13/19 |
| | | | | | | | 0.000027 lb/MM Btu | 346 MW | CMN20190001 | 1/25/19 |

**Footnotes:** Previous performance tests are listed in the previous Statement of Basis.

## SECTION 4 – SOURCE INFORMATION AND REQUIREMENTS

**Table A - Group Requirements:**

| Emission and Operating Limit | Regulation | Emission Unit |
|---|---|---|
| Annual coal throughput for EU 03 and 35 shall not exceed 463,566 tpy each. | 401 KAR 51:017, *Prevention of significant deterioration of air quality*, Section 9 | 03, 35 |
| $NO_X$ emissions from the combined stack for EU 01 and 02 shall not exceed 890 lb/hr on a 24-hr block average basis. | 401 KAR 51:017, *Prevention of significant deterioration of air quality*, Section 9 | 01, 02 |
| 8,000 tons $NO_X$ on a 12-month rolling total | Consent Decree entered September 24, 2007, Section V | EKPC System |
| 28,000 tons $SO_2$ on a 12-month rolling total | Consent Decree entered September 24, 2007, Section VI | EKPC System |
| $SO_2$ emissions shall not exceed 1,800 tons per year on a 12-month rolling total | 40 CFR 51.1203(b) and (e)(1) | Source-wide |

**Table B - Summary of Applicable Regulations:**

| Applicable Regulations | Emission Unit |
|---|---|
| 401 KAR 51:017, *Prevention of significant deterioration of air quality* | 02 17, 18, 19, 20, 21, 22, 23, 24, 25, 26A, 26B, 27, 28, 29A, 29B, 29C, 30, 31, 32, 33, 34, 35 |
| 401 KAR 51:160, *$NO_X$ requirements for large utility and industrial boilers* | 01, 02, 18, 19 |
| 401 KAR 51:210, *CAIR, $NO_X$ annual trading program* | 01, 02, 18, 19, |
| 401 KAR 51:220, *CAIR, $NO_X$ ozone season trading program* | 01, 02, 18, 19 |
| 401 KAR 51:230, *CAIR, $SO_2$ trading program* | 01, 02 18, 19 |
| 401 KAR 51:240, *Cross-State Air Pollution Rule (CSAPR) $NO_X$ annual trading program* | 01, 02, 18, 19 |
| 401 KAR 51:250, *Cross-State Air Pollution Rule (CSAPR) $NO_X$ ozone season group 2 trading program* | 01, 02, 18, 19 |

| | |
|---|---|
| 401 KAR 51:260, *Cross-State Air Pollution Rule (CSAPR) $SO_2$ group 1 trading program* | 01, 02, 18, 19 |
| 40 CFR 52, Subpart S *Kentucky* | 01, 02 |
| 401 KAR 52:060, *Acid rain permits* | 01, 02, 18, 19 |
| 401 KAR 59:010, *New process operations* | 04, 05, 09, 25, 29B, 29C |
| 401 KAR 59:015, *New indirect heat exchangers* | 17, 20, 23, 24, 29A |
| 401 KAR 60:005, Section 2(2)(d), 40 C.F.R. 60.40c to 60.48c (Subpart Dc), *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* | 17, 20 |
| 401 KAR 60:005, Section 2(2) (dddd), 40 CFR 60.4200 through 60.4219, Tables 1 through 8 (Subpart IIII), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* | 21, 22 |
| 401 KAR 60:005, Section 2(2)(eeee) 40 CFR 60.4230 through 60.4248, Tables 1 through 4 (Subpart JJJJ), *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines* | 12 |
| 401 KAR 60:005, Section 2(2)(ffff), 40 CFR 60.4300a through 60.4420a, Tables 1 through 3 (Subpart KKKKa), *Standards of Performance for Stationary Combustion Turbines* | 18, 19 |
| 401 KAR 60:005, Section 2(2)(wwww), 40 CFR 60.5508a through 60.5580a, Tables 1 through 3 (Subpart TTTTa), *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* | 18, 19 |
| 401 KAR 61:015, *Existing indirect heat exchangers* | 01, 02 |
| 401 KAR 63:002, Section 2(4)(dddd), 40 CFR 63.6080 through 63.6175, Tables 1 through 7 (Subpart YYYY), *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* | 18, 19 |
| 401 KAR 63:002, Section 2(4)(eeee), 40 CFR 63.6580 through 63.6675, Tables 1a through 8, and Appendix A (Subpart ZZZZ), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* | 08, 12, 13, 21, 22 |
| 401 KAR 63:002, Section 2(4)(iiii), 40 CFR 63.7480 through 63.7575, Tables 1 through 13 (Subpart DDDDD), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* | 17, 20, 23, 24 |
| 401 KAR 63:002, Section 2(4)(yyyy), 40 CFR63.9980 through 63.10042, Tables 1 through 9, and Appendices A through E (Subpart UUUUU), *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* | 01, 02 |

| | |
|---|---|
| 401 KAR 63:010, *Fugitive emissions* | 03, 10, 32, 35 |
| 401 KAR 63:020, *Potentially hazardous matter or toxic substances* | 26A, 26B, 27, 28, 29A, 29B, 29C, 33 |
| 40 CFR Part 64, *Compliance Assurance Monitoring* | 09-03, 09-04, 09-07, 18, 19 |
| 40 CFR Part 75, *Continuous Emission Monitoring* | 01, 02, 18, 19 |

**Table C - Summary of Precluded Regulations:**

| **Precluded Regulations** | **Emission Unit** |
|---|---|
| 401 KAR 63:002, Section 2(4)(j), 40 CFR 63.400 through 63.407, Table 1 (Subpart Q), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Colling Towers* | 04, 25 |

**Table D - Summary of Non Applicable Regulations:**

| **Non Applicable Regulations** | **Emission Unit** |
|---|---|
| 401 KAR 60:005, Section 2(2)(b), 40 CFR 60.40Da through 60.52Da (Subpart Da), *Standards of Performance for Electric Utility Steam Generating Units* | 02 |

**Air Toxic Analysis**
N/A

**Single Source Determination**
N/A

## SECTION 5 – COMPLIANCE ASSURANCE MONITORING

**40 CFR 64**, *Compliance assurance monitoring* (CAM) applies to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under 40 CFR 64.2(b)(1);

(2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source.

| Emission Unit | Criteria 1 (Y/N) | Criteria 2 (Y/N) | Criteria 3 (Y/N) | Does CAM apply? If Y for criteria 1, 2, AND 3, then Yes, Otherwise, No. |
|---|---|---|---|---|
| 1 | Y | Y | Y | Yes |
| 2 | Y | Y | Y | Yes |
| 3 | N | N | N | No |
| 4 | N | Y | N | No |
| 5 | Y | N | N | No |
| 8 | N | N | N | No |
| 9 | Y | Y | Y | Yes |
| 10 | N | N | N | No |
| 12 | N | N | N | No |
| 13 | N | N | N | No |
| 17 | Y | Y | N | No |
| 18 | Y | Y | Y | Yes |
| 19 | Y | Y | Y | Yes |
| 20 | Y | Y | N | No |
| 21 | Y | N | N | No |
| 22 | Y | N | N | No |
| 23 | Y | Y | N | No |
| 24 | Y | Y | N | No |
| 25 | Y | N | N | No |
| 26A | N | N | N | No |
| 26B | N | N | N | No |
| 27 | N | N | N | No |
| 28 | N | N | N | No |
| 29A | Y | N | N | No |
| 29B | Y | N | N | No |
| 29C | Y | N | N | No |
| 30 | Y | N | N | No |
| 31 | Y | N | N | No |
| 32 | N | N | N | No |
| 33 | N | N | N | No |

| | | | | |
|---|---|---|---|---|
| 34 | N | N | N | No |
| 35 | N | N | N | No |

* If Yes, CAM applies for any of the emission units above, then see further clarification for each listed emission unit in **Section 3**.

## SECTION 6 – PERMITTING HISTORY

| Permit | Permit Type | Activity # | Complete Date | Issuance Date | Summary of Action | PSD/Syn Minor |
|---|---|---|---|---|---|---|
| V-97-044 | Title V | APE20050001 | 2/11/1997 | 11/12/1999 | Initial Title V w/ Acid Rain Permit | N/A |
| A-98-012 | Acid Rain Permit | | | 3/5/1999 (Effective 1/1/2000) | Final Phase II Acid Rain Permit | N/A |
| V-05-082 | Title V Renewal Permit w/ Acid Rain Permit and $NO_X$ Budget Permit | APE20040002 | 9/27/2004 | 1/8/2007 | Title V Renewal Permit w/ Acid Rain Permit and $NO_X$ Budget Permits | N/A |
| V-05-082 R1 | Minor Revision | APE20070001 | 3/23/2007 | 6/20/2007 | Added Secondary Fuel for Units 01 and 02 of up to 3% Wood Waste, and a new cooling tower | N/A |
| V-05-082 R2 | Significant Revision | APE20090001 | 9/27/2004 | 9/29/2010 | Added SCR, FGD, fabric filter to Unit 2 and associated material handling, incorporate Consent Decree requirements, CAIR | N/A |
| V-12-019 | Renewal | APE20110005 | 9/4/2011 | 8/14/2013 | Title V Renewal Permit incorporating Consent Decree and EGU MACT requirements | N/A |
| V-12-019 R1 | Significant Revision | APE20130001 | 9/4/2011 | 10/10/2014 | Add DFGD/PJFF to Unit 1, incorporate BART SIP requirements, | N/A |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | updated CAM plan, and EU 15 | |
| V-12-019 R2 | Significant Revision | APE20150002 | 1/8/2016 | 6/17/2016 | Addition of $SO_2$ limit to Unit 1 and source-wide $SO_2$ limit | N/A |
| V-18-027 | Renewal | APE20180001 | 5/21/2018 | 9/7/2020 | Renewal, Consent Decree Termination, adding PM CAM requirement | N/A |

## SECTION 7 – PERMIT APPLICATION HISTORY

N/A

## APPENDIX A – ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| 4SLB | – 4-Stroke Lean Burn |
| AAQS | – Ambient Air Quality Standards |
| AP-42 | – Compilation of Air Pollutant Emission Factors |
| AQRV | - Air Quality Related Values |
| BACT | – Best Available Control Technology |
| Be | – Beryllium |
| Btu | – British thermal unit |
| CAIR | – Clean Air Interstate Rule |
| CAM | – Compliance Assurance Monitoring |
| CCR | – Coal Combustion Residuals |
| CD | – Consent Decree |
| CEMS | – Continuous Emissions Monitoring System |
| $CH_4$ | – Methane |
| CFR | – Code of Federal Regulations |
| CI | – Compression Ignition |
| CO | – Carbon Monoxide |
| CPMS | – Continuous Parametric Monitoring System |
| CSAPR | – Cross State Air Pollution Rule |
| CT | – Combustion Turbine |
| DB | – Duct Burner |
| Division | – Kentucky Division for Air Quality |
| dscf | – Dry Standard Cubic Feet |
| DSI | – Dry Sorbent Injection |
| EGU | – Electric Generating Unit |
| ESP | – Electrostatic Precipitator |
| EPA | – Environmental Protection Agency |
| EU | – Emission Unit |
| FGD | – Flue Gas Desulfurization |
| GHG | – Greenhouse Gas |
| gpm | – Gallons per Minute |
| gr | – Grain(s) |
| GWh | – Gigawatt Hour |
| HAP | – Hazardous Air Pollutant |
| HF | – Hydrogen Fluoride (Gaseous) |
| HHV | – Higher Heating Value |
| HP | – Horsepower |
| hr | – Hour |
| HRSG | – Heat Recovery Steam Generator |
| ID | – Identification |
| ISO | – International Organization for Standardization |
| J | – Joule(s) |
| KAR | – Kentucky Administrative Regulations |
| KU | – Kentucky Utilities |
| kW | – Kilowatt |
| lb | – Pound |
| LNB | – Low $NO_x$ Burners |

MACT – Maximum Achievable Control Technology
MATS – Mercury Air Toxic Standards
min – Minute
MSDS – Material Safety Data Sheets
MMBtu – Million Btu
mmHg – Millimeter of mercury column height
MMgal – Million gallons
MMscf – Million standard cubic feet
MW – Megawatt
MWh – Megawatt Hour
NAAQS – National Ambient Air Quality Standards
NESHAP – National Emissions Standards for Hazardous Air Pollutants
ng – Nanogram(s)
NG – Natural Gas
NGCC – Natural Gas Combined Cycle
NMHC – Non-Methane HydroCarbon
NOD – Notice of Deficiency
NOV – Notice of Violation
$NO_x$ – Nitrogen Oxides
NSPS – New Source Performance Standards
NSR – New Source Review
$O_2$ – Oxygen
PAC – Powdered Activated Carbon
PJFF – Pulse Jet Fabric Filter
PM – Particulate Matter
$PM_{10}$ – Particulate Matter equal to or smaller than 10 micrometers
$PM_{2.5}$ – Particulate Matter equal to or smaller than 2.5 micrometers
Ppbvd – Parts per billion by volume on a dry basis
ppmvd – Parts per million by volume on a dry basis
PSD – Prevention of Significant Deterioration
PTE – Potential to Emit
RICE – Reciprocating Internal Combustion Engine
SAM – Sulfuric Acid Mist
SCC – Standard Classification Code
SCR – Selective Catalytic Reduction
$SO_2$ – Sulfur Dioxide
TF – Total Fluoride (Particulate & Gaseous)
tpy – Ton(s) per Year
ULSFO – Ultra Low Sulfur Fuel Oil
VMT – Vehicle Miles Travelled
VOC – Volatile Organic Compounds
yr – Year