Commonwealth of Kentucky
Division for Air Quality

STATEMENT OF BASIS / SUMMARY

Title V, Construction / Operating
PERMIT ID: V-26-036

Kentucky Utilities Company – E.W. Brown Generating Station
Harrodsburg, KY 40330

June 17, 2026
John Jerrod Mays and Stacie Daniels, P.E., Reviewers

Source ID: 21-167-00001
Agency Interest #: 3148
Activity ID: APE20230005 and APE20250001

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SECTION 1 - SOURCE DESCRIPTION

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

Single Source Det. ☐ Yes ☒ No

Source-wide Limit ☐ Yes ☒ No

28 Source Category ☒ Yes ☐ No If Yes, Category: Fossil fuel-fired steam electric plants of more than 250 million BTUs per hour heat input.

County: Mercer
Nonattainment Area ☒ N/A ☐ PM_{10} ☐ $PM_{2.5}$ ☐ CO ☐ NO_X ☐ SO_2 ☐ Ozone ☐ Lead

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): Hydrochloric acid, Hydrofluoric acid

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

*PTE does not include self-imposed emission limitations.

Description of Facility:
Kentucky Utilities Company (KU) operates the E.W. Brown Generating Station (Brown Station) in Mercer County, Kentucky. The plant is located at 815 Dix Dam Road in Burgin, Kentucky and is approximately 25 miles southwest of Lexington, Kentucky and 9 miles east northeast of Harrodsburg, Kentucky.

Brown Station is an electric generating power plant that began operation in the 1950s 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) program. Mercer County is classified as attainment or unclassifiable for all pollutants. 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-26-036

Activity	Application Received	Application Complete
APE20230005	12/8/2023	2/6/2024
APE20250001	3/27/2025	5/26/2025

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:
APE20220002: Off Permit Change received 3/2/2022 to modify insignificant activity 39 and add a diesel fuel tank to the list of insignificant activities.

APE20220005: Off Permit Change received 4/28/2022 to move EUs 47 and 48 from New Emergency CI RICE to New CI Emergency Fire Pump RICE with EUs 45 and 46.

APE20230005: Renewal application received 12/8/2023, more than six months prior to the expiration (June 8, 2024) of their current Title V operating permit, V-17-030 R1. The application includes updates to 40 CFR 63, Subpart UUUUU and addition of insignificant activities. The Division also updated the 401 KAR 61:015 PM emission limitation for Emission Unit 3.

APE20240004: 502(b)(10) Change received on 6/4/2024 to replace EU 39, a gasoline RICE generator, and EU 40, a diesel RICE generator, with two new Tier III certified diesel RICE generators (EUs 71 & 72), regulated by 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ.

APE20250001: Significant PSD Revision application received 3/17/2025 to install EU 58, a new 681 MW (gross) natural gas-fired combined cycle (NGCC) electric generating unit (EGU), and its associated ancillary equipment. The support equipment includes the following:

- EU 59: 95.52 MMBtu/hr auxiliary boiler;
- EU 60: 15.65 MMBtu/hr dewpoint preheater;
- EU 61: 2.18 MW emergency CI generator RICE;
- EU 62: 422 HP emergency CI fire pump RICE;
- EU 63: 10-cell mechanical draft cooling tower;
- EU 64: 30-pound and 330-pound SF_6 circuit breakers;
- EU 65: Lube oil system with demister vents;
- EU 66: 3,733-gallon diesel storage tank for EU 61 generator;
- EU 67: 300-gallon diesel storage tank for EU 62 fire pump;
- EU 68: Paved haul roads;
- EU 69: Natural gas piping; and
- EU 70: 93 wt% sulfuric acid tank.

Due to the project's 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. Analysis of the NGCC project is provided after the V-26-036 Emission Summary table.

V-26-036 Emission Summary				
Pollutant	2025 Actual (tpy)	Previous PTE V-17-030 R1 (tpy)	Change[1] (tpy)	Revised PTE V-26-036 (tpy)
CO	179.15	1,453.53	148.72	1,602.25
NO_X	402.34	1,867.20	167.98	2,035.18
PT	95.97	889.69	97.63	987.32
PM_{10}	47.82	869.35	101.35	970.70
$PM_{2.5}$	20.26	457.49	100.87	558.36
SO_2	652.17	2,844.23	35.46	2879.69
VOC	22.58	92.92	43.94	136.86
Lead	0.00	0.16	0.03	0.19
Greenhouse Gases (GHGs)				
Carbon Dioxide	1,846,380	8,369,464	2,302,905	10,672,369
Methane	23.39	118.66	63.68	182.34
Nitrous Oxide	31.07	46.69	4.43	51.12
CO_2 Equivalent (CO_2e)[2]	1,855,268	8,385,159	2,305,862	10,691,021
Hazardous Air Pollutants (HAPs)				
Acetaldehyde	--	1.12	0.34	1.46
Ammonia (anhydrous)	N/A	--	--	138.00
Arsenic, Total (as As)	--	0.55	--	0.55
Benzene	0.00	2.01	0.06	2.07
Benzyl Chloride	--	0.74	--	0.74
Ethyl Benzene	--	0.49	0.29	0.78
Formaldehyde	0.79	12.41	0.99	13.40
Hexane	0.00	0.20	2.06	2.26
Hydrochloric Acid	95.67	1,266.17	--	1,266.17
Hydrofluoric Acid	7.63	158.27	--	158.27
Isophorone	--	0.61	--	0.61
Manganese, Total (as Mn)	--	9.23	0.01	9.24
Methyl Chloride	--	0.56	--	0.56
Propylene Oxide	--	0.37	-0.07	0.30
Selenium, Total (as Se)	--	1.65	--	1.65
Sulfuric Acid	20.81	473.1	23.72	496.82
Toluene	0.00	1.91	-0.29	1.62
Xylenes (Total)	0.00	0.84	-0.14	0.70
Combined HAPs:	124.9	1,460.43	500.77	1,961.20

1 In addition to the PSD project discussed in the remainder of **Section 2 – Current Application and Emission Summary Form**, emission units and factors have been added and updated, as described under **Description of Action**.

2 Global warming potentials of 28 and 265 are used for methane and nitrous oxide, respectively.

PSD Applicability Analysis:
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 this project, as KU Brown Station is an existing major stationary source located in Mercer 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. Emissions:

A. Project PSD Significance:

In the application to construct and operate a combined cycle combustion turbine and ancillary equipment, KU Brown calculated the potential air pollutants emitted from the project. The new equipment is expected to be a source of these regulated NSR pollutants: NO_x, CO, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, lead, and GHGs.

Potential to emit pollutants from this facility were calculated based on emission factors obtained from U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, engineering estimates, mass balances, and manufacturer's specifications. Based on these emission factors and the assumption of a 24-hour, 7 days a week, 52 weeks a year (8,760 hours per year) operation unless otherwise limited, the potential emissions of regulated NSR pollutants, CO, NO_x, $PM_{2.5}$, PM_{10}, PM, VOC, H_2SO_4, and GHGs exceed the thresholds as indicated in the Project PSD Significance Table below. Discussion of each pollutant, sources, calculation assumptions, emission factor sources, and the pollutant's PSD significance follows.

Project PSD Significance

Pollutant	PEI (tpy)	SER (tpy)	PEI > SER?
CO	148.9	100	**Yes**
NO_x	168.9	40	**Yes**
SO_2	27.2	40	No
$PM_{2.5}$	101.0	10	**Yes**
PM_{10}	102.0	15	**Yes**
PM	103.3	25	**Yes**
VOC	67.2	40	**Yes**
Lead	0.001	0.6	No
H_2SO_4	23.7	7	**Yes**
CO_2e [a]	2,292,461	75,000	**Yes**

a. Since PSD has been triggered by other NSR pollutants, greenhouse gases (GHGs or CO_2e) are subject to the PSD applicability test.

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). No existing units are being modified, so KU Brown performed a PSD analysis to determine the project's emissions increases utilizing only the actual-to-potential test for new units. Fugitive emissions are included, because KU Brown is included in the 28-source categories in 401 KAR 51:001, Section 1(118)(c). There were no projects completed during the 5-year contemporaneous period, so the **project emissions increases (PEI)** are equal to the net emissions increases for all NSR pollutants.

B. <u>Carbon Monoxide (CO) Emissions</u>

CO is a colorless, odorless gas that contributes to smog and can be harmful when inhaled in large amounts. It forms primarily through incomplete combustion, the partial oxidation of carbon-containing compounds. This project's CO emissions come from the combustion of natural gas and diesel. All calculations utilize a site-specific natural gas higher heating value (HHV) of 1,053 Btu/scf.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

CO is calculated utilizing a controlled, KU-required vendor guarantee of 2.0 ppmvd at 15% O_2 during steady-state operations (with and without duct burners). The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of CO. Assuming 8,760 hours per year firing the DBs with no SU or SD events, CO emissions are 90.8 tpy during steady-state operation. GE vendor data provides data for startup (SU) and shutdown (SD) emissions as shown in the CO Emissions from Startup and Shutdown table:

<u>CO Emissions from Startup and Shutdown</u>

SU/SD Event	Events Per Year	CO Emission Factor (lb/event)	CO Emissions (tpy)
Cold SU	10	758	3.8
Warm SU	50	476	11.9
Hot SU	125	303	18.9
SD	185	244	22.6
		Total:	57.2

Cold starts take 73-280 minutes to ramp up and are preceded by over 72 hours of SD; warm starts take 63-89 minutes to ramp up and are preceded by 8-72 hours of SD; hot starts take 33-54 minutes to ramp up and are preceded by 0-8 hours of SD. Shutdowns occur for 12-21 minutes. Since SU/SD events are uncontrolled, including them represents the worst case. Assuming the maximum amount of SU/SD events taking the least amount of time for each event, hours during steady-state operation are limited to 7,470 hours per year, resulting in steady-state emissions of 77.4 tpy of CO for a total CO PTE of **134.6 tpy** from EU 58. The worst-case PTE for CO includes SU/SD emissions.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

CO emissions from EUs 59 and 60 are generated from the burning of natural gas at 95.52 and 15.65 MMBtu/hr, respectively. KU requires a vendor guarantee of 50 ppmv CO at 3% O_2, or 38.9 lb/MMscf, converted from ppmv utilizing the molecular weight of CO, molar volume of a gas at 528 °R and 1 atm, and the dry F factor for natural gas from Table 19-2 in Appendix A-7 to 40 CFR part 60. Potential to emit calculations are based on the assumption that EU 59 operates at a federally enforceable maximum of 4,000 hours per year resulting in potential CO emissions of **7.01 tpy**. Potential CO emissions from EU 60 at 8,760 hours per year are **2.52 tpy**.

iv. EU 61: 2.18 MW Diesel Emergency Generator

v. EU 62: 422 HP Diesel Emergency Fire Pump

CO emissions from EUs 61 and 62 are generated from the burning of diesel fuel at 149 and 22 gal/hr, respectively. Potential emission calculations are based on the 40 CFR 60, Subpart IIII emission standard and an appropriate default assumption of 500 hours per year of operation, resulting in potential CO emissions of **4.19 tpy** from EU 61 and **0.60 tpy** from EU 62.

CO PSD Significance

The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show the potential controlled CO emissions for this project to be 148.9 tpy, as seen in the *CO PSD Significance* table below. This emission rate exceeds the PSD significant emission increase of 100 tpy allowed for an existing major stationary source, so a BACT analysis for CO is required for each piece of equipment that emits CO. Refer to the **BACT Analysis for CO** under Section 2.II.A. for a discussion of BACT.

CO PSD Significance

Emission Unit	CO (tpy)
58	134.61
59	7.01
60	2.52
61	4.19
62	0.60
Total:	**148.9**

C. Nitrogen Oxides (NO_x) Emissions:

NO_x, primarily nitric oxide (NO) and nitrogen dioxide (NO_2), reacts in the atmosphere to form ozone and acid rain. In addition to environmental impacts, long-term exposure to NO_x can lead to various health problems. 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.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

NO_x is calculated utilizing a controlled, KU-required vendor guarantee of 2.0 ppmvd at 15% O_2 during steady-state operations (with and without duct burners). The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of NO_x. Assuming 8,760 hours per year firing the DBs with no SU or SD events and a site-specific higher heating value of 1,053 Btu/scf, NO_x emissions are 149.1 tpy during steady-state operation. GE vendor data provides data for startup (SU) and shutdown (SD) emissions as shown:

NO_x Emissions from Startup and Shutdown

SU/SD Event	Events Per Year	NO_x Emission Factor (lb/event)	NO_x Emissions (tpy)
Cold SU	10	420	2.1
Warm SU	50	260	6.5
Hot SU	125	135	8.4
SD	185	78	7.2
		Total:	24.2

The worst-case PTE for NO_x includes SU/SD emissions. Assuming the maximum amount of SU/SD events at the least amount of time for each event, hours during steady-state operation are limited to 7,470 hours per year (see explanation under Section 2.I.B.i.). CO Emissions for EU 58). Steady-state emissions at 7,470 hours per year, excluding SU/SD emissions, are 127.1 tpy of NO_x for a total NO_x PTE, including SU/SD emissions, of **151.4 tpy**.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

NO_x emissions from EUs 59 and 60 are generated from the burning of natural gas at 95.52 and 15.65 MMBtu/hr, respectively. NO_x control for this equipment includes low NO_x burners and flue gas recirculation. KU requires a vendor guarantee of 30 ppmv NO_x at 3% O_2, or 38.3 lb/MMscf, converted from ppmv utilizing the molecular weight of NO_x, molar volume of a gas at 528 °R and 1 atm, and the dry F factor for natural gas from Table 19-2 in Appendix A-7 to 40 CFR part 60. Potential to emit calculations are based on the assumption that EU 59 operates at a federally enforceable maximum of 4,000 hours per year resulting in potential NO_x emissions of **6.95 tpy**. Potential NO_x emissions from EU 60 at 8,760 hours per year are **2.49 tpy**.

iv. EU 61: 2.18 MW Diesel Emergency Generator

v. EU 62: 422 HP Diesel Emergency Fire Pump

NO_x emissions from EUs 61 and 62 are generated from the burning of diesel fuel at 149 and 22 gal/hr, respectively. Potential emission calculations are calculated at 500 hours per year and are based on the 40 CFR 60, Subpart IIII emission standard for NO_x + NMHC multiplied by the ratio of emissions from AP-42 of NO_x divided by (NO_x + TOC), resulting in potential NO_x emissions of **7.42 tpy** from EU 61 and **0.64 tpy** from EU 62.

NO_x PSD Significance

The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show potential controlled NO_x emissions for this project to be 168.9 tpy, as totaled in the *NO_x PSD Significance* table below. This emission rate exceeds the PSD significant emission increase of 40 tpy allowed for an existing major stationary source, so a BACT analysis for NO_x is required for each piece of equipment that emits NO_x. Refer to the **BACT Analysis for NO_x** under Section 2.II.B. for a discussion of BACT.

NO_x PSD Significance

Emission Unit	NO_x (tpy)
58	151.39
59	6.95
60	2.49
61	7.42
62	0.64
Total:	**168.9**

D. 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. 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.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

$PM/PM_{10}/PM_{2.5}$ emissions are calculated utilizing vendor supplied data. The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of PM. During periods of startup and shutdown, PM emissions are less than during steady-state operation. Therefore, worst-case PTE calculations assume 8,760 hours per year firing the DBs at steady-state with no SU or SD events and a site-specific higher heating value of 1,053 Btu/scf. Potential PM emissions are **98.9 tpy**.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from the burning of natural gas at 95.52 MMBtu/hr. Potential emissions are calculated using vendor data and are based on the assumption that the equipment operates at a maximum of 4,000 hours per year. Potential $PM/PM_{10}/PM_{2.5}$ emissions are **1.3 tpy**.

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from the burning of natural gas at 15.65 MMBtu/hr. Potential emissions are calculated using vendor data and are based on the assumption that the equipment operates every hour throughout the year (8,760 hours). Potential $PM/PM_{10}/PM_{2.5}$ emissions are **0.48 tpy**.

iv. EU 61: 2.18 MW Diesel Emergency Generator

$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from the burning of diesel fuel at 149 gal/hr. PTE calculations are based on gallons of diesel consumed per hour and a conservative 500 hours of operation per year to account for emergencies. Potential $PM/PM_{10}/PM_{2.5}$ emissions are **0.24 tpy**.

v. **EU 62: 422 HP Diesel Emergency Fire Pump**
$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from the burning of diesel fuel at 22 gal/hr. PTE calculations are based on gallons of diesel consumed per hour and a conservative 500 hours of operation per year to account for emergencies. Potential $PM/PM_{10}/PM_{2.5}$ emissions are **0.03 tpy**.

vi. **EU 63: 10-Cell Mechanical Draft Cooling Tower**
$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from the particulates encapsulated in the water droplets. PTE calculations are based on 95,000 gallons of recirculating water per minute with total dissolved solids of 990 ppm and a drift percentage of 0.0010% after the drift eliminators. At 8,760 hours per year, potential PM, PM_{10}, and $PM_{2.5}$ emissions are **2.06, 0.97,** and **0.004 tpy**, respectively.

vii. **EU 68: NGCC Paved Haul Roads**
$PM/PM_{10}/PM_{2.5}$ emissions from this unit are generated from vehicle transport of aqueous ammonia, cooling tower chemicals, and water treatment chemicals on paved haul roads. PTE calculations are based on weight and the number of miles traveled per year. Potential PM, PM_{10}, and $PM_{2.5}$ emissions are **0.24, 0.05,** and **0.007 tpy**, respectively.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Significance
The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show potential controlled $PM/PM_{10}/PM_{2.5}$ emissions for this project to be 103.3, 102.0, and 101.0 tpy, respectively, as can be seen in the *Particulate Matter PSD Significance* table below. This emission rate exceeds the PSD significant emission increase of 25, 15, and 10 tpy, respectively, allowed for an existing major stationary source. Therefore, a BACT analysis for $PM/PM_{10}/PM_{2.5}$ is required for each piece of equipment that emits $PM/PM_{10}/PM_{2.5}$. Refer to the **BACT Analysis for $PM/PM_{10}/PM_{2.5}$** under Section 2.II.C. for a discussion of BACT.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) PSD Significance

Emission Unit	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
58	98.90	98.90	98.90
59	1.34	1.34	1.34
60	0.48	0.48	0.48
61	0.24	0.24	0.24
62	0.03	0.03	0.03
63	2.06	0.97	0.004
68	0.24	0.05	0.007
Total:	**103.3**	**102.0**	**101.0**

E. **Volatile Organic Compound (VOC) Emissions:**
Volatile Organic Compounds (VOCs) are gases that are a component in the formation of the criteria pollutant, Ozone. As with CO emissions, any equipment that burns fossil fuel is a source of VOCs. Additionally, the emission points involved in this project produce

VOCs through the storage and transmission of fuels. Temperature and residence time are also drivers of VOC formation.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

VOC is calculated utilizing a controlled, KU-required vendor guarantee of 1.0 ppmvd (as CH_4) at 15% O_2 during steady-state operations with duct burners firing and 2.0 ppmvd (as CH_4) at 15% O_2 during steady-state operations without duct burners. The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of VOC. Assuming 8,760 hours per year firing the DBs with no SU or SD events and a site-specific higher heating value of 1,053 Btu/scf, VOC emissions are 52 tpy during steady-state operation. GE vendor data provides data for startup (SU) and shutdown (SD) emissions as shown:

VOC Emissions from Startup and Shutdown

SU/SD Event	Events Per Year	VOC Emission Factor (lb/event)	VOC Emissions (tpy)
Cold SU	10	135	0.68
Warm SU	50	121	3.03
Hot SU	125	91	5.69
SD	185	118	10.92
		Total:	20.3

The worst-case PTE for VOC includes SU/SD emissions. Assuming the maximum number of SU/SD events taking the least amount of time for each event, hours during steady-state operation are limited to 7,470 hours per year (see explanation under I.B.i. CO Emissions for EU 58). Steady-state emissions of VOC at 7,470 hours per year are 44.3 tpy of VOC for a total VOC PTE of **64.6 tpy**, including SU/SD emissions.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

VOC emissions from this unit are generated from the burning of natural gas at 95.52 MMBtu/hr. Potential emission calculations for VOCs uses a conservative vendor estimate of 5.5 lb/MMscf and the assumption that the equipment operates at a maximum of 4,000 hours per year . Potential VOC emissions are **1 tpy.**

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

VOC emissions from this unit are generated from the burning of natural gas at 15.65 MMBtu/hr. Potential VOC emissions are calculated using a vendor estimate of 8.4 lb/MMscf and assumes the equipment operates constantly throughout the year (8,760 hours). Potential VOC emissions are **0.53 tpy**.

iv. EU 61: 2.18 MW Diesel Emergency Generator

v. EU 62: 422 HP Diesel Emergency Fire Pump

VOC emissions from EUs 61 and 62 are generated from the burning of diesel fuel at 149 gal/hr and 22 gal/hr, respectively. Potential emission calculations are calculated at 500 hours per year and are based on the 40 CFR 60, Subpart IIII emission standard for NO_x + NMHC multiplied by the ratio of emissions from AP-42 of TOC divided by (NO_x + TOC), resulting in potential VOC emissions of **0.2 tpy** from EU 61 and

0.05 tpy from EU 62. For the purposes of these calculations, VOC, NMHC, and TOC are used interchangeably.

vi. EU 65: Lube Oil System with Demister Vents

EU 58 and its associated steam turbine will be equipped with an internal lube oil storage and distribution system. A small quantity of the lube oil present in the system will be vaporized due to the high operating temperatures inside the turbine systems, potentially resulting in VOC emissions from the lube oil systems. The GT will be equipped with a demister system to avoid lube oil loss to the atmosphere to the extent possible; however, a small quantity of lube oil will be emitted, as VOC from the lube oil demister vents. There are no VOC control devices for this emission unit. PTE calculations assume a maximum lube oil loss of 0.5 gallons per day and convert the gallons to VOC by using the density of the oil and assuming 100% VOC content. Potential VOC emissions from EU 65 are **0.66 tpy**.

vii. EU 66: 3,733-gal Diesel Storage Tank for Generator

viii. EU 67: 300-gal Diesel Storage Tank for Fire Pump

VOC emissions from EUs 66 and 67 are generated through the normal operation of the fuel tanks. Breathing losses occur as the fuel is stored in the tank over time and working losses occur as fuel is being filled and/or dispensed – both of which produce 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. PTE calculations utilize TankESP software using methodology presented in AP-42, Section 7.1. The usage assumes each emergency engine needs fuel to operate 500 hours per year. Potential VOC emissions, including both working and breathing losses, are **0.008 tpy** for EU 66 and **0.00004 tpy** for EU 67.

ix. EU 69: Natural Gas Piping Fugitives

VOC emissions from EU 69 are generated through leaks during the normal operation of natural gas flowing through pipes installed as part of the PSD project. The types of components where leakage could occur include valves, relief valves, flanges, vents, compressors, and sampling connections. The potential VOC emissions are calculated using the number of each component type, site specific natural gas VOC content weight percentages, and EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates Table 2-4. Potential VOC emissions from EU 69 are **0.09 tpy**.

<u>**VOC PSD Significance**</u>

The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show the potential controlled VOC emissions for this project to be 67.2 tpy (See table below this paragraph). This emission rate exceeds the PSD significant emission increase of 40 tpy allowed for an existing major stationary source, so a BACT analysis for VOC is required for each piece of equipment that emits VOC. Refer to the **BACT Analysis for VOC** in Section 2.II.D. for a discussion of VOC BACT.

VOC PSD Significance

Emission Unit	VOC (tpy)
58	64.64
59	1.00
60	0.53
61	0.20
62	0.05
65	0.66
66	0.008
67	0.00004
69	0.09
Total:	**67.2**

F. Sulfuric Acid Mist (SAM or H_2SO_4) Emissions:

SAM emissions are generated 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 operation, duct burner operation, 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 SAM, as is the storage of sulfuric acid.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

SAM emissions are calculated utilizing equipment vendor specified data and natural gas pipeline specifications. The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of SAM. Assuming 8,760 hours per year firing the DBs with no SU or SD events results in the highest PTE for SAM of **23.69 tpy**.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

SAM emissions from EUs 59 and 60 are generated from the burning of natural gas at 95.52 MMBtu/hr. Potential emissions conservatively assume 100% of the maximum natural gas sulfur content is converted to SO_2, 5% of the SO_2 is converted to SO_3, and 100% of the SO_3 is converted to H_2SO_4. Calculations are based on standard cubic feet of natural gas consumed per hour and the assumption that the auxiliary boiler operates at a maximum of 4,000 hours per year. Potential SAM emissions are **0.02 tpy** from EU 59 and **0.007 tpy** from EU 60.

iv. EU 70: 93% Sulfuric Acid Tank

SAM emissions from this unit are generated through the normal operation of this sulfuric acid tank. Breathing losses occur over time as the sulfuric acid is stored and working losses occur as sulfuric acid is being filled and/or dispensed – both of which produce SAM 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 sulfuric acid in gallons per year. Potential SAM emissions, including both working and breathing losses, are **0.0000004 tpy**.

Sulfuric Acid Mist (SAM or H_2SO_4) PSD Significance

The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show the potential controlled SAM emissions for this project to be 23.7 tpy as shown in the SAM PSD Significance table below. This emission rate exceeds the PSD significant emission increase of 7 tpy allowed for an existing major stationary source, so a BACT analysis for SAM is required for each piece of equipment that emits SAM. Refer to **BACT Analysis for H_2SO_4** in Section 2.II.E. for a discussion of BACT.

Sulfuric Acid Mist (SAM or H_2SO_4)
PSD Significance

Emission Unit	H_2SO_4 (tpy)
58	23.69
59	0.02
60	0.007
70	0.000000434
Total:	**23.7**

G. Greenhouse Gas (GHG or CO_2e) Emissions:

GHG emissions originate from the combustion of fossil fuels, fugitive methane leaks from natural gas piping, and sulfur hexafluoride leakage from the circuit breakers.

i. EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB

Greenhouse gas emissions are calculated utilizing emission factors and higher heating values from 40 CFR 98, Tables C-1 and C-2 and global warming potentials from 40 CFR 98, Table A-1. The maximum heat input capacity is higher while firing the DBs, resulting in higher emissions of greenhouse gases. Assuming 8,760 hours per year firing the DBs with no SU or SD events, potential greenhouse gas emissions are **2,261,306 tpy**.

ii. EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler

GHG emissions from the auxiliary boiler are generated from the burning of natural gas at 95.52 MMBtu/hr. Potential emissions are calculated utilizing emission factors and higher heating values from 40 CFR 98, Tables C-1 and C-2 and global warming potentials from 40 CFR 98, Table A-1. Calculations are based on the maximum standard cubic feet of natural gas consumed and the assumption that the equipment operates at a maximum of 4,000 hours per year. Potential GHG emissions are **21,797 tpy.**

iii. EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater

GHG emissions from this unit are calculated using emission factors and the higher heating value from 40 CFR 98, Tables C-1 and C-2 and global warming potentials from 40 CFR 98, Table A-1. Calculations are based on standard cubic feet of natural gas consumed and the assumption that the equipment operates constantly throughout the year (8,760 hours). Potential GHG emissions are **7,821 tpy**.

iv. EU 61: 2.18 MW Diesel Emergency Generator

v. EU 62: 422 HP Diesel Emergency Fire Pump
GHG emissions from these units are calculated using emission factors and the higher heating value from 40 CFR 98, Tables C-1 and C-2 and global warming potentials from 40 CFR 98, Table A-1. PTE calculations are based on gallons of diesel consumed per year using a conservative 500 hours of operation to account for emergencies. Potential GHG emissions are **835 tpy** from EU 61 and **121 tpy** from EU 62.

vi. EU 64: Turbine Circuit Breakers with a 30-lb and 330-lb SF_6 Circuit
GHG emissions from EU 64 are generated from leaks of SF_6 to the atmosphere. Calculations are based on a maximum leak rate of 0.5% per year. Potential GHG emissions are **21.15 tpy**.

vii. EU 69: Natural Gas Piping Components
GHG emissions from this unit are generated through leaks during normal operation as natural gas flows through piping installed as part of the PSD project. These GHG emissions are calculated using the number of each component type, site specific natural gas VOC content weight percentages, and Table 2-4 in EPA-453/R-95-017 *Protocol for Equipment Leak Emission Estimates*. Potential GHG emissions are **559.86 tpy**.

GHG PSD Significance
The emissions calculations, using the maximum potential throughputs and accepted emission factors for each piece of equipment, show the potential controlled GHG emissions for this project to be 2,292,461 tpy as shown in the GHG PSD Significance table below. This emission rate exceeds the PSD significant emission increase of 75,000 tpy allowed for an existing major stationary source, so a BACT analysis for GHG is required for each piece of equipment that emits GHGs. Refer to the **BACT Analysis for Greenhouse Gas (GHG or CO_2e)** in Section 2.II.F. for a discussion of GHG BACT.

GHG PSD Significance

Emission Unit	GHGs (tpy)
58	2,261,306
59	21,797
60	7,821
61	835
62	121
64	21.2
69	560
Total:	**2,292,461**

II. BACT Analysis:
The following is a summary of the various BACT analyses along with the emission limitations 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 is 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, but not limited to:

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

For each emission unit with the potential to emit the section's 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 control technology analysis is followed by a summary of the BACT requirements for each unit. The permit has requirements to ensure the BACT limits are federally enforceable. Section 3 of this Statement of Basis and Summary document outlines the testing, monitoring, recordkeeping, and reporting requirements needed to demonstrate compliance with the BACT limits for each emission unit being added as part of the NGCC project at KU Brown.

The majority of the project's emissions are from the project's largest unit, the combined cycle combustion turbine electric generating unit (EGU). Both pre-combustion and post-combustion control technologies are considered. Efficient design of the EGU is considered a pre-combustion control and is crucial to minimizing emissions of air pollutants. As the thermal efficiency of the unit increases, less fuel is combusted per gross MWh of electricity produced, and there is a corresponding decrease in air emissions. The most efficient conditions include operating at base load, low ambient temperatures, and high relative humidity.

The EGU KU Brown has chosen for this project is GE's 7HA.03, which utilizes turbine design technology with advanced turbine cooling, sealing, materials, and coating. An increased compressor inlet and turbine exit annulus areas, combined with an increased pressure ratio to maintain flow, increases power output of these units. The 7HA.03 is the third generation of GE's 7HA turbines, designed to be more efficient than their previous counterparts. Advanced technology and design are incorporated into the EGU, including inlet air filters, an evaporative cooler when ambient temperatures are warm and relative humidity is low, and dry low NO_x burners. In addition, emission reductions are achieved by operating at a base load, which runs continuously at a consistent output level, rather than a peaking unit, which turns on and off frequently to meet short-term demand spikes.

While add-on controls can greatly reduce certain pollutants, they also require electricity to operate. Auxiliary load requirements reduce the net efficiency of the EGU, so add-on controls have undergone a high level of scrutiny. The Division establishes these BACT emission limitations based on emissions reductions achieved by EGU facilities in the last five years.

A. <u>BACT Analysis for CO</u>:
Technologies Reviewed:
<u>Oxidation Catalyst</u>
Oxidation catalysts are materials that lower the activation energy and temperature required for oxidation, resulting in accelerated oxidation reactions, particularly by adsorbing CO in the exhaust gas and O_2 from the air stream to produce CO_2. 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 an oxidation catalyst to control CO emissions.

<u>Good Combustion and Operating Practices (GCOP)</u>
GCOP is a pre-combustion control to optimize combustion. 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. By taking measures to optimize the combustion process, pollutants are minimized. Although GCOP is not an add-on control, efficient operation of combustion equipment is an effective means to reduce CO and other pollutants from combustion operating parameters should be controlled to optimize combustion zone temperature, mixing, and residence time. Work practices such as performing inspections and preventative maintenance keep equipment running in optimal ranges and prevent extra pollution caused by malfunction. The equipment must be routinely evaluated and inspected by personnel trained to maintain the specific equipment.

i. *<u>EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB</u>*
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of an oxidation catalyst and GCOP constitutes BACT for CO.

Emission Point	BACT	BACT Limit for CO	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	Oxidation Catalyst and GCOP	2.0 ppmvd at 15% O_2	24-hour rolling, excluding SU/SD	CO CEMS
		134.6 tpy	12-month rolling, including SU/SD	

Analysis: KU Brown presents possible control technologies for CO from the combined cycle gas turbine. EM_x™, $SCONO_x$™, and METEOR™ technology has not been used commercially for large combustion turbines due to engineering challenges and is considered technically infeasible. KU Brown proposes using an oxidation catalyst in conjunction with GCOP, as it provides the greatest emission reduction potential. An oxidation catalyst system will be installed and operated with or without the DBs.

KU Brown proposed a BACT limit of 2.0 ppmvd at 15% O_2 on a 30-day average basis, excluding startups and shutdowns with compliance demonstrated using CO CEMS. The Division agrees with the steady-state emission limit of 2.0 ppmvd at 15% O_2, but a 24-hour rolling averaging period will provide a more accurate representation and align better with the national ambient air quality standards (NAAQS) for CO. A shorter averaging period will ensure compliance with the BACT limits and the NAAQS, allowing for timely corrective actions should any deviations occur.

CO emissions from SU/SD are higher than during steady-state operation, because the controls take time to reach the design conditions. Considering an adequate, conservative number of SU/SD events, potential emissions are limited to 134.6 tpy on a 12-month rolling total basis. See Section 2.**I.B.i.** above for potential CO emission calculations.

ii. *<u>EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler</u>*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of GCOP, specifically good design and operating practices constitutes BACT for CO.

Emission Point	BACT	BACT Limit for CO	BACT Limit Averaging Period	Compliance Demonstration
59	GCOP	0.037 lb/MMBtu	3-hour block average	Performance Testing
		7.0 tpy	12-month rolling total	
		4,000 hours of operation	12-month rolling total	Monitoring and Recordkeeping

Analysis: KU Brown evaluates an oxidation catalyst as BACT for CO for the auxiliary steam boiler. An oxidation catalyst is a technically feasible option with a potential control efficiency between 50 and 90 percent. However, an oxidation catalyst was eliminated while evaluating the energy, economic and environmental impacts.

The steam load can vary considerably throughout the day, depending on weather conditions, so a high turndown ratio of 10:1 is required to support the range of operating loads (10-100% of maximum continuous rating, or MCR). Oxidation catalysts are limited to a turndown of 4:1, or 25% of the MCR. Without the 10:1 operational flexibility, the boiler would need to run at a higher load during lower demand. Also, the number of SU/SD events increases with a higher turndown ratio, increasing the wear and tear on the boiler. Finally, operating at higher loads than necessary requires more fuel consumption, resulting in higher emissions of all pollutants. Due to these energy and environmental impacts, the oxidation catalyst was eliminated as a feasible option for this emission unit.

The auxiliary boiler is operated to assist with warm and cold startups of the combustion turbine and to provide freeze protection during downtime in the winter months for the HRSG. Although KU Brown anticipates needing the boiler for less than 25% of turbine operation, they have requested a limit of 4,000 hours per calendar year to provide operational flexibility. The Division has accepted the 4,000 hours and made it a federally enforceable limit on a 12-month rolling total basis to smooth out the effect of seasonal variations.

iii. *EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of GCOP constitutes BACT for CO.

Emission Point	BACT	BACT Limit for CO	BACT Limit Averaging Period	Compliance Demonstration
60	GCOP	0.037 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	

Analysis: KU Brown does not evaluate an oxidation catalyst as BACT for CO for the dewpoint heater, as their use has not been demonstrated commercially for these heaters. Even if an oxidation catalyst is a technically feasible option, it would not be economically feasible, as CO emissions are only 2.5 tpy, so the cost would be at least $40,000 per ton of CO removed.

GCOP for CO reduction includes controlling the air/oxygen supply and maintaining the temperature in the combustion chambers for maximum efficiency. Additionally, KU Brown requires the manufacturer to guarantee CO emissions at or below 0.037 lb/MMBtu.

iv. *EU 61: 2.18 MW Diesel Emergency Generator;* and *EU 62: 422 HP Diesel Emergency Fire Pump*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of combustion design controls and GCOP constitutes BACT for CO.

Emission Point	BACT	BACT Limit for CO	BACT Limit Averaging Period	Compliance Demonstration
61	GCOP	2.6 g/HP-hr (0.0057 lb/HP-hr)	N/A	Certified engines
62				

Analysis: Although thermal or catalytic oxidation technologies are technically feasible for non-emergency engines, they are not considered technically feasible for emergency engines. The maintenance checks and readiness testing requires the engines to be turned on regularly for a short period of time, typically one hour. Post-combustion controls require the exhaust to reach a certain temperature before reaching the design control efficiency, and there isn't adequate run-time for emergency engines to make a control feasible. The BACT limit proposed for these units matches the limits set by 40 CFR 60, Subpart IIII.

B. BACT Analysis for NO_x:

Technologies Reviewed:

Dry Low NO_x (DLN) Combustion Technology and Ultra Low NO_x Burners (LNB)

LNBs pre-mix air and natural gas prior to injection into the combustion turbine, reducing peak flame temperature and thermal NO_x formation.

Flue Gas Recirculation (FGR)

FGR routes a portion of the flue gas back to the burner. It lowers the temperature of the flame to reduce thermal NO_x production by minimizing excess oxygen in the air/fuel mixture. The recirculation rate has to be controlled to ensure enough oxygen is present to maximize complete fuel combustion.

Good Combustion and Operating Practices (GCOP)

GCOP maximizes efficiency to create the most energy with the least amount of pollution. Maintaining the air-to-fuel ratio is crucial for minimizing NO_x emissions. Control systems automatically adjust operating parameters to enhance combustion efficiency.

EM_x^{TM}/$SCONO_x^{TM}$/$METEOR^{TM}$

EM_x^{TM}, $SCONO_x^{TM}$, and $METEOR^{TM}$ are multi-pollutant post combustion control technologies. The control efficiency for NO_x is about the same or lower than SCRs. EM_x^{TM}/$SCONO_x^{TM}$ removes NO_x without using a reagent, such as NH_3, whereas $METEOR^{TM}$ 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 SAM 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 SAM than natural gas.

NO_x reduction efficiency depends on the stoichiometric injection of ammonia, type of catalyst used, and the exhaust gas temperature. For the combined cycle units, the SCR system is located downstream of the turbine where the temperature is between 600- and 700-degrees Fahrenheit, an adequate range for a conventional vanadium/titanium catalyst. 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. 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 1600 to 2000 degrees Fahrenheit to avoid ammonia slip.

i. *EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB*
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of a SCR, DLN Burners and GCOP constitutes BACT for NO_x.

Emission Point	BACT	BACT Limit for NO_x	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	SCR, DLN Burners, & GCOP	2.0 ppmvd at 15% O_2	24-hour rolling, excluding SU/SD	NO_x CEMS
		151.4 tpy	12-month rolling, including SU/SD	

Analysis: KU Brown presents possible control technologies for NO_x from the combined cycle gas turbine. EM_x^{TM}, $SCONO_x^{TM}$, and METEOR^{TM} technology has not been used commercially for large combustion turbines due to engineering challenges and is considered technically infeasible. SNCR and FGR are also technically infeasible, as neither are used for large, commercial turbines. These technologies are not considered further in the BACT analysis. SCRs provide about 90% destruction efficiency. DLN and GCOP are part of the turbine design and destruction efficiency varies.

KU Brown proposed a NO_x limit of 2.0 ppmvd at 15% O_2 on a 30-day rolling average basis, excluding SU/SD emissions. Compliance can be demonstrated using NO_x CEMS. The Division agrees with the proposed BACT limit using a 24-hour rolling average basis rather than a 30-day rolling average. A shorter averaging period will ensure compliance with the BACT limits and the NAAQS, allowing for timely corrective actions should any deviations occur.

The post-combustion controls take time to achieve the rated destruction efficiency, so when the system is starting up and shutting down, emissions of NO_x are considered uncontrolled. Without limiting the number of startups and shutdowns, KU Brown is taking an annual NO_x BACT limit of 151.4 tpy on a 12-month rolling total basis, including SU/SD events. See Section 2.**I.C.i.** for potential NO_x emission calculations.

ii. *EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler*
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of LNB with FGR and GCOP constitutes BACT for NO_x.

Emission Point	BACT	BACT Limit for NO_x	BACT Limit Averaging Period	Compliance Demonstration
59	LNB with FGR and GCOP	0.036 lb/MMBtu	3-hour block average	Performance Testing
		7.0 tpy	12-month rolling total	
		4,000 hours of operation	12-month rolling total	Monitoring & Recordkeeping

Analysis: EM_x™, $SCONO_x$™, and METEOR™ technology has not been used commercially for small boilers so is considered unavailable. The remaining control technologies are presented below:

Rank	Control Technology	Potential Control Efficiency (%)
1	SCR	50-90
2	Ultra LNB	70-76
3	SNCR	40-60
4	LNB with FGR	Varies (Base Case)

KU Brown estimates annualized costs of the SCR, considering LNB with FGR as the base case NO_x control, results in a cost of $53,060 per ton in 2024 dollars. Similarly, SNCR would cost approximately $41,195 per ton of NO_x removed (in 2024 dollars). The Division agrees these NO_x control technologies are cost prohibitive.

Ultra LNBs require a 4:1 turndown whereas this auxiliary boiler regularly requires a 10:1 turndown. More energy (and fuel) would be needed to increase the load from 10% to 25%, and steam vents would need to be added to remove the excess energy. Ultra LNBs result in adverse energy and environmental impacts and are therefore removed from consideration as a feasible NO_x control on this unit.

LNBs with FGR are commercially available and economically feasible for this size boiler. GCOP for NO_x reduction includes controlling the air/oxygen supply and maintaining the temperature in the combustion chambers for maximum efficiency. Additionally, KU Brown requires the manufacturer to guarantee NO_x emissions at or below 0.036 lb/MMBtu.

The auxiliary boiler is operated to assist with warm and cold startups of the combustion turbine and to provide freeze protection during downtime in the winter months for the HRSG. Although KU Brown anticipates needing the boiler for less than 25% of turbine operation, they have requested a limit of 4,000 hours per calendar year to provide operational flexibility. The Division has accepted the 4,000 hours but on a 12-month rolling total basis to smooth out the effect of seasonal variations.

iii. ***EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater***

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of LNBs and GCOP constitutes BACT for NO_x.

Emission Point	BACT	BACT Limit for NO_x	BACT Limit Averaging Period	Compliance Demonstration
60	LNBs & GCOP	0.036 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	

Analysis: EM_x™, $SCONO_x$™, and METEOR™ technology has not been used commercially for small boilers so is considered unavailable. FGR isn't used in boilers of this size, as the burner flame zone is less accessible than for larger boilers. The exhaust temperature for this heater is about 500 degrees Fahrenheit, which falls outside of the range for SCR and SNCR to be feasible.

LNBs provide a control efficiency between 38% and 63% and are commercially available and economically feasible for this size boiler. GCOP for NO_x reduction includes controlling the air/oxygen supply and maintaining the temperature in the combustion chambers for maximum efficiency. Additionally, KU Brown requires the manufacturer to guarantee NO_x emissions at or below 0.036 lb/MMBtu.

iv. ***EU 61: 2.18 MW Diesel Emergency Generator;*** **and**
EU 62: 422 HP Diesel Emergency Fire Pump

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of combustion design controls and GCOP constitutes BACT for NO_x.

Emission Point	BACT	BACT Limit for NO_x + VOC	BACT Limit Averaging Period	Compliance Demonstration
61	GCOP	4.8 g/HP-hr (0.0066 lb/HP-hr)	N/A	Certified engines
62		3.0 g/HP-hr (0.0106 lb/HP-hr)		

Analysis: Although SCR & SNCR technologies are technically feasible for non-emergency engines, they are not considered technically feasible for emergency engines. The maintenance checks and readiness testing requires the engines to be turned on regularly for a short period of time, typically one hour. Post-combustion controls require the exhaust to reach a certain temperature before reaching the design control efficiency, and there isn't adequate run-time for emergency engines to make an add-on control feasible. Additionally, ammonia or urea slip from the controls would pose adverse environmental impacts. The BACT limit proposed for these units matches the limits set by 40 CFR 60, Subpart IIII for NO_x + NMHC (Non-Methane HydroCarbons).

C. BACT Analysis for $PM/PM_{10}/PM_{2.5}$:

Technologies Reviewed:

Multicyclone, Wet Scrubber, ElectroStatic Precipitator (ESP), and Baghouse

While this technology exists, they are not technically feasible options for the combined cycle gas turbines nor any of the ancillary equipment, as they have never been installed commercially.

Catalyzed Diesel Particulate Filter (CDPF)

This technology is used to remove PM from diesel and gasoline engine exhausts. A catalyst is applied onto the filter media to promote 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.

Inlet Air Filters

Inlet air filters reduce the amount of solid PM entrained in the combustion air that enters the combustion chamber.

Advanced Drift Eliminators

Advanced drift eliminators are add-on controls for cooling towers designed to minimize the escape of water droplets into the atmosphere. They reduce drift formation, which reduces PM, PM_{10}, and $PM_{2.5}$ that's entrained in the water droplets.

Low-Sulfur Fuel

Sulfur in the exhaust gas increases PM, as it reacts in the gas stream to form solid sulfur compounds. Natural gas and ultra low sulfur diesel have inherently low sulfur contents.

Good Combustion and Operating Practices (GCOP)

GCOP minimizes PM emissions by ensuring efficient combustion procedures are implemented. Controlling fuel feed rates, air to fuel ratios, and periodic tuning all contribute to PM reductions.

i. *EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of inlet air filters, low sulfur fuel, and GCOP constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	BACT Limit for $PM/PM_{10}/PM_{2.5}$	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	Inlet air filters, low sulfur fuel, & GCOP	0.005 lb/MMBtu	3-hour block average	Performance Testing
		98.9 tpy	12-month rolling	Monitoring & recordkeeping

Analysis: KU Brown presents possible control technologies for $PM/PM_{10}/PM_{2.5}$ from the combined cycle gas turbine. Reduction of PM emissions varies for inlet air filters, low sulfur fuel, and GCOP. KU Brown proposes a $PM/PM_{10}/PM_{2.5}$ BACT limit of 0.005 lb/MMBtu, with compliance demonstrated by performance testing. In addition, inlet air filters will be part of the turbine design, and the sulfur content of the fuel will not exceed 0.5 gr/100 dscf, as supplied by the vendor. The Division requires current, valid gas analysis records from the vendor to be maintained on site. See Section 2.**I.D.i.** above for potential PM emission calculations.

ii. ***<u>EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler</u>***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of inlet air filters, low sulfur fuel, and GCOP constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	BACT Limit for $PM/PM_{10}/PM_{2.5}$ (filterable + condensable)	BACT Limit Averaging Period	Compliance Demonstration
59	Low sulfur fuel & GCOP	0.0070 lb/MMBtu	3-hour block average	Performance Testing
		1.3 tpy	12-month rolling total	Pipeline quality NG
		0.5 grains sulfur per 100 dscf	N/A	Current Vendor Specs
		4,000 hours of operation	12-month rolling total	Monitoring & Recordkeeping

Analysis: Commercial auxiliary steam boilers do not utilize controls for PM. Pipeline quality natural gas combustion inherently emits very little PM which is usually less than one micrometer in diameter. KU Brown requires emissions from this boiler to be at most 7.14 lb/MMscf, resulting in a PM PTE of 1.3 tpy. Therefore, any additional control would be, at a minimum, economically infeasible.

The auxiliary boiler is operated to assist with warm and cold startups of the combustion turbine and to provide freeze protection during downtime in the winter months for the HRSG. Although KU Brown anticipates needing the boiler for less than 25% of turbine operation, they have requested a limit of 4,000 hours per calendar year to provide operational flexibility. The Division has accepted the 4,000 hours but on a 12-month rolling total basis to smooth out the effect of seasonal variations.

iii. ***<u>EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater</u>***
Decision Summary: The Division determines the use of low sulfur fuel and GCOP constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	BACT Limit for $PM/PM_{10}/PM_{2.5}$ (filterable plus condensable)	BACT Limit Averaging Period	Compliance Demonstration
60	Low sulfur fuel & GCOP	0.007 lb/MMBtu	3-hour block average	Performance Testing
		0.5 tpy	12-month rolling total	Pipeline quality NG
		0.5 grains sulfur per 100 dscf	N/A	Current Vendor Specs

Analysis: Pipeline quality natural gas combustion inherently emits very little PM which is usually less than one micrometer in diameter. PM emissions are less than 1 tpy, so any additional control would be, at a minimum, economically infeasible.

v. ***EU 61: 2.18 MW Diesel Emergency Generator;*** **and**
EU 62: 422 HP Diesel Emergency Fire Pump
Decision Summary: The Division determines the use of low sulfur fuel and GCOP, including combustion design controls and usage limitations, constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	BACT Limit for $PM/PM_{10}/PM_{2.5}$	Compliance Demonstration
61 & 62	GCOP	0.15 g/HP-hr (0.0003 lb/HP-hr)	Certified engines

Analysis: CDPF controls can reduce PM by up to 94%; however, EPA has determined these controls to be economically infeasible for emergency engines.

iv. ***EU 63: 10-Cell Mechanical Draft Cooling Tower***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of advanced drift eliminators constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	PM	BACT Limit	Compliance Demonstration
63	Advanced Drift Eliminators	PM	0.47 lb/hr	0.001% drift loss or less; TDS less than 990 ppm
			2.07 tpy	
		PM_{10}	0.22 lb/hr	
			0.97 tpy	
		$PM_{2.5}$	$9.50x10^{-4}$ lb/hr	
			$4.16x10^{-3}$ tpy	

Analysis: PM emissions from cooling towers are a function of water recirculation rate, drift loss, and the concentration of total dissolved solids (TDS). The planned TDS concentration is 990 ppm. Minimizing TDS and advanced drift eliminators are two ways cooling tower PM emissions can be alleviated.

v. ***EU 68: NGCC Paved Haul Roads***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of paved roads and best management practices constitutes BACT for $PM/PM_{10}/PM_{2.5}$.

Emission Point	BACT	Compliance Demonstration
68	Paved Roads & Best Management Practices	Dust control plan; records of control measures taken

Analysis: KU Brown identified the following control options for haul roads: paving roadways, sweeping roadways, wet or chemical suppression, and good housekeeping.

All options will be applied as BACT to minimize fugitive dust emissions due to road traffic. Speed limit signs will also be posted to minimize fugitive dust emissions.

D. BACT Analysis for VOC:

Technologies Reviewed:

Oxidation Catalyst

Oxidation catalysts are materials that lower the activation energy and temperature required for oxidation, resulting in accelerated oxidation reactions, particularly converting VOCs in the exhaust gas to CO_2. Destruction efficiencies for VOC are typically 90% or more, depending on the catalyst used, operating temperature, residence time and the presence of other pollutants.

EM_x™/$SCONO_x$™/METEOR™

EM_x™, $SCONO_x$™, and METEOR™ are multi-pollutant post combustion control technologies that use an oxidation catalyst to control VOC emissions. The destruction efficiency for VOC is approximately the same as that for other oxidation catalysts, so the technology will not be further evaluated for VOC control.

Good Combustion and Operating Practices (GCOP)

GCOP includes equipment design and operation consistent with good combustion practices to minimize emissions. Operating parameters should be controlled to optimize combustion, including, but not limited to, temperature, turbulence, and residence time. Work practices such as performing inspections and preventative maintenance keep equipment running in optimal ranges and prevent extra pollution caused by malfunction. The equipment must be routinely evaluated and inspected by personnel trained to maintain the specific equipment.

i. *EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of an oxidation catalyst and GCOP constitutes BACT for VOC.

Emission Point	BACT	BACT Limit for VOC	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	Oxidation catalyst and GCOP	1.0 ppmvd (as CH_4) at 15% O_2 without DBs	3-hour block average, excluding SU/SD	Performance Testing; Monitor Flue Gas Flowrate, Oxidation catalyst Inlet Temperature, and Pressure Drop across Catalyst
		2.0 ppmvd (as CH_4) at 15% O_2 with DBs		
		64.6 tpy	12-month rolling, including SU/SD	

Analysis: KU Brown presents possible control technologies for VOC from the combined cycle gas turbine. EM_x™, $SCONO_x$™, and METEOR™ technology has not been used commercially for large combustion turbines due to engineering challenges and is considered technically infeasible. KU Brown proposes using an oxidation catalyst in conjunction with GCOP, as it provides the greatest technically feasible emission reduction potential. An oxidation catalyst system will be installed and operated with or without the DBs. A performance test will be conducted to determine compliance with the BACT emission limits and to establish operating parameters. The flue gas flow rate, inlet temperature, and pressure drop across the catalyst will be monitored during the performance test to establish ranges for the parameters.

VOC emissions from SU/SD are higher than during steady-state operation, because the controls take time to reach their designed destruction efficiency. Considering an adequate and conservative number of SU/SD events, potential emissions are limited to 64.6 tpy on a 12-month rolling total basis. See Section 2.**I.E.i.** for potential VOC emission calculations.

ii. ***<u>EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler</u>***

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of GCOP, specifically good design and operating practices constitutes BACT for VOC.

Emission Point	BACT	BACT Limit for VOC	BACT Limit Averaging Period	Compliance Demonstration
59	GCOP	0.0052 lb/MMBtu	3-hour block average	Performance Testing
		1.0 tpy	12-month rolling total	Pipeline quality NG
		4,000 hours of operation	12-month rolling total	Monitoring & Recordkeeping

Analysis: KU Brown evaluates an oxidation catalyst as BACT for VOC for the auxiliary steam boiler. An oxidation catalyst is a technically feasible option with a potential control efficiency between 50 and 60 percent. However, an oxidation catalyst was eliminated while evaluating the energy, economic and environmental impacts.

The steam load can vary considerably throughout the day, depending on weather conditions, so a high turndown ratio of 10:1 is required to support the range of operating loads (10-100% of maximum continuous rating, or MCR). Oxidation catalysts are limited to a turndown of 4:1, or 25% of the MCR. Without the 10:1 operational flexibility, the boiler would need to run at a higher load during lower demand. Also, the number of SU/SD events increases with a higher turndown ratio, increasing the wear and tear on the boiler. Finally, operating at higher loads than necessary requires more fuel consumption, resulting in higher emissions of all pollutants. Due to these energy and environmental impacts, the oxidation catalyst was eliminated as a feasible option for this emission unit.

The auxiliary boiler is operated to assist with warm and cold startups of the combustion turbine and to provide freeze protection during downtime in the winter months for the HRSG. Although KU Brown anticipates needing the boiler for less than 25% of turbine operation, they have requested a limit of 4,000 hours per calendar year to provide operational flexibility. The Division has accepted the 4,000 hours but on a 12-month rolling total basis to smooth out the effect of seasonal variations.

iii. *EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of GCOP constitutes BACT for VOC.

Emission Point	BACT	BACT Limit for VOC	BACT Limit Averaging Period	Compliance Demonstration
60	GCOP	0.008 lb/MMBtu	3-hour block average	Combustion of pipeline quality natural gas & maintaining/operating in accordance with manufacturer's recommendations
		0.5 tpy	12-month rolling total	

Analysis: KU Brown does not evaluate an oxidation catalyst as BACT for VOC for the dewpoint heater, as their use has not been demonstrated commercially for these heaters. Even if an oxidation catalyst is a technically feasible option, it would not be economically feasible, as VOC emissions are less than 1 tpy.

GCOP for VOC reduction includes controlling the air/oxygen supply and maintaining the temperature in the combustion chambers for maximum efficiency. The BACT limit submitted by KU Brown is based on the vendor's engineering estimate of VOC emissions from the heater.

iv. *EU 61: 2.18 MW Diesel Emergency Generator;* and
EU 62: 422 HP Diesel Emergency Fire Pump

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of combustion design controls and GCOP constitutes BACT for VOC.

Emission Point	BACT	BACT Limit for NO_x + VOC	BACT Limit Averaging Period	Compliance Demonstration
61	GCOP	4.8 g/HP-hr (0.0066 lb/HP-hr)	N/A	Certified engines
62		3.0 g/HP-hr (0.0106 lb/HP-hr)		

Analysis: Although thermal or catalytic oxidation technologies are technically feasible for non-emergency engines, they are not considered technically feasible for emergency engines. The maintenance checks and readiness testing requires the engines to be turned on regularly for a short period of time, typically one hour. Post-combustion controls require the exhaust to reach a certain temperature before reaching the design control efficiency, and there isn't adequate run-time for emergency engines to make an add-on control feasible. The BACT limit proposed for these units matches the limits set by 40 CFR 60, Subpart IIII for NO_x + NMHC (Non-Methane HydroCarbons).

v. ***EU 65: Lube Oil System with Demister Vents***

Decision Summary: The Division determines the use of demister vents constitutes BACT for VOC.

Emission Point	BACT	Compliance Demonstration
65	Demister Vents	Maintain & operate in accordance with manufacturer's recommendations

Analysis: KU Brown did not propose any BACT for the lube oil system due to the lack of available control options and the low annual PTE (See Section 2.I.E.vi. above for VOC emission information). A small quantity of the lube oil present in the system will be vaporized due to the high operating temperatures inside the turbine system, potentially resulting in VOC emissions from the lube oil systems. Demister vents are incorporated into the lube oil system to capture aerosolized oil droplets, forming larger droplets that can be reused in the system. The demister vents reduce the amount of oil droplets being released into the atmosphere. The Division has determined BACT for the lube oil system to be the demister vents with compliance demonstrated through maintenance of the lube oil system and demister records.

vi. ***EU 66: 3,733-gal Diesel Storage Tank for Generator***
EU 67: 300-gal Diesel Storage Tank for Fire Pump

Decision Summary: The Division determines the use of submerged fill pipes constitutes BACT for VOC.

Emission Point	BACT	BACT Limit for VOC	BACT Limit Averaging Period	Compliance Demonstration
66 & 67	Submerged Fill Pipe	N/A	N/A	Install and operate submerged fill pipe

Analysis: KU Brown did not propose any BACT for the diesel storage tanks due to the lack of available control options and the low annual PTE. If a submerged fill pipe is not incorporated into the design of the storage tanks, KU Brown must install one to avoid splash loading and reduce the amount of VOC emitted into the ambient air.

vii. *EU 69: Natural Gas Piping Fugitives*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of AVO constitutes BACT for GHGs.

Emission Point	BACT	BACT Limit for VOC	BACT Limit Averaging Period	Compliance Demonstration
69	AVO	N/A	N/A	Recordkeeping of AVO inspections

Analysis: KU Brown identifies component type/design, leak inspections, and low-leaking components as potential BACT. KU Brown will incorporate low-leaking components into the design of their process. LDAR was determined to be cost prohibitive, so regular AVO inspections will be conducted at least once per month instead.

E. BACT Analysis for H_2SO_4:

Technologies Reviewed:

Flue Gas Desulfurization (FGD) Scrubbers

FGD scrubbers are control devices that utilize absorption and reaction using an alkaline reagent to produce a solid compound. This technology is commonly used on high sulfur fuel combustion units, such as coal- and oil-fired EGUs.

Dry Sorbent Injection (DSI)

DSI injects selected sorbents into the flue gas to control pollutants. It's primarily used on coal-fired boilers to remove SO_2 and HCl prior to exhaust.

Low-Sulfur Fuel

The mechanisms that form H_2SO_4 require sulfur availability in the fuel. Natural gas and ultra low sulfur diesel have inherently low sulfur contents.

Good Combustion and Operating Practices (GCOP)

GCOP minimizes H_2SO_4 emissions by ensuring efficient combustion procedures are implemented, reducing the amount of fuel needed for combustion. H_2SO_4 can also be formed from catalyst-induced oxidation of SO_2 in the SCR. Using a low sulfur fuel alleviates the burden on the catalyst, because the formation of ammonium sulfate and ammonium bisulfate is minimal.

i. *EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of low sulfur fuel and GCOP constitutes BACT for H_2SO_4.

Emission Point	BACT	BACT Limit for H_2SO_4	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	Low sulfur fuel & GCOP	0.5 grains sulfur per 100 dscf (fuel specification)	N/A	Current Vendor Specs

Analysis: KU Brown presents possible control technologies for H_2SO_4 from the combined cycle gas turbine. While FGD scrubbers and DSI are existing technologies to control H_2SO_4, they have never been installed on a commercial NGCC EGU, and KU Brown therefore asserts they are cost prohibitive or technically infeasible. Additionally, there are no relevant NSPS, NESHAPs, or state regulations to establish a floor of allowable H_2SO_4. KU Brown proposes using fuel with a maximum sulfur content of 0.5 grains per 100 dscf in conjunction with GCOP.

ii. ***<u>EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler</u>***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of low sulfur fuel and GCOP constitutes BACT for H_2SO_4.

Emission Point	BACT	BACT Limit for H_2SO_4	BACT Limit Averaging Period	Compliance Demonstration
59	Low sulfur fuel & GCOP	0.5 grains sulfur per 100 dscf (fuel specification)	N/A	Current Vendor Specs
		4,000 hours of operation	12-month rolling total	Monitoring & Recordkeeping

Analysis: KU Brown presents possible control technologies for H_2SO_4 from the combined cycle gas turbine. While FGD scrubbers and DSI exist to control H_2SO_4, they are cost prohibitive to install on a unit of this size. There are no relevant NSPS, NESHAPs, or state regulations to establish a floor of allowable H_2SO_4, but emissions should be minimal using pipeline quality natural gas. KU Brown proposes using fuel with a maximum sulfur content of 0.5 grains per 100 dscf in conjunction with GCOP.

iii. ***<u>EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater</u>***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of low sulfur fuel and GCOP constitutes BACT for H_2SO_4.

Emission Point	BACT	BACT Limit for H_2SO_4	BACT Limit Averaging Period	Compliance Demonstration
60	Low sulfur fuel & GCOP	0.5 grains sulfur per 100 dscf (fuel specification)	N/A	Current Vendor Specs

Analysis: KU Brown presents possible control technologies for H_2SO_4, and while FGD scrubbers and DSI are existing technologies to control H_2SO_4, they are cost prohibitive to install on a unit of this size There are no relevant NSPS, NESHAPs, or state regulations to establish a floor of allowable H_2SO_4. KU Brown proposes using fuel with a maximum sulfur content of 0.5 grains per 100 dscf in conjunction with GCOP.

iv. ***EU 70: 93% Sulfuric Acid Tank***
Decision Summary: The Division determines the use of manufacturer's recommended procedures constitutes BACT for H_2SO_4.

Emission Point	BACT	BACT Limit for H_2SO_4	BACT Limit Averaging Period	Compliance Demonstration
70	Manufacturer's recommended procedures	N/A	N/A	Maintain a copy of manufacturer's recommendations, tank inspections, and maintenance conducted

Analysis: KU Brown did not perform a full top-down BACT analysis for this unit, as there are no control options feasible 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.

F. **BACT Analysis for CO_2e:**
Technologies Reviewed:
Carbon Capture and Sequestration/Storage (CCS)
CCS is an available technology for the gas turbine, EU 58. It involves capturing CO_2 by absorption, adsorption, membranes, or cryogenic separation, compressing the CO_2 into supercritical conditions, transporting it by pipeline or truck, and injecting it for long-term geologic storage. Currently, there are no EPA-approved injection sites in Kentucky for commercial-scale storage.

Alternative Fuels-Biomass/Co-Firing Low Carbon Fuel
Alternative fuels include animal meal, waste wood products/sawdust, and sewage sludge. Biomass materials can also be specifically cultivated for use as a fuel source. CO_2 could potentially be reduced by switching to a different fuel.

Leak Inspections
Leak inspections can be performed to identify any fugitive leaks in piping and the circuit breaker. Leak Detection and Repair (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fittings, and sampling connections. Audio, Visual, or Olfactory (AVO) leak detection can be used on its own or as part of LDAR to listen for leak sounds, scan for signs of leaks, and smell any odors.

Good Combustion and Operating Practices (GCOP)
GCOP ensures the process is optimized, increasing efficiency and minimizing emissions.

i. *EU 58 (Unit 12): 681 MW (gross) Gas Turbine with HRSG and DB*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of efficient turbine operation and good combustion, operating and maintenance practices constitute BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	BACT Limit Averaging Period	Compliance Demonstration
58 (Unit 12)	GCOP	925 lb/MWh (gross) CO_2 without DBs	12-month rolling total	See **5. Specific Recordkeeping Requirements** d. and **6. Specific Reporting Requirements** b. and c
		815 lb/MWh (gross) CO_2 with DBs		
		2,289,969 tpy		

Analysis: CCS has been tested on a pilot scale and had been moving from pilot scale tests to large-scale commercial operations. However, the Department of Energy (DOE) cancelled clean energy grants for carbon capture and decarbonization on May 30, 2025. The CCS technology is not currently technically feasible, as the technology has not been demonstrated for NGCC EGUs, there are no existing or planned pipelines for CO_2 transport, and there are no existing or planned commercially available sequestration sites within a reasonable distance.

GCOP includes efficient turbine design with controls to optimize fuel combustion and sufficient insulation to minimize energy loss. There is also an operating and maintenance plan to maintain the unit at its design efficiency and operating parameters.

ii. *EU 59: 95.52 MMBtu/hr Auxiliary Steam Boiler*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of GCOP constitutes BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	Compliance Demonstration
59	GCOP	114.0 lb/MMBtu	Monitoring & Recordkeeping
		21,797 tpy	
		4,000 hours of operation	

Analysis: Of the fossil fuels considered, natural gas emits less CO_2 than its liquid and solid counterparts. Operating with a fuel other than natural gas would alter the design and purpose of the boiler, so this is not a technically feasible option. Furthermore, emissions of other pollutants, such as CO and NO_x, could potentially increase with the use of an alternative fuel, which would result in negative environmental impacts.

GCOP ensures the boiler experiences less deterioration, maintaining its efficiency. It includes efficient burner design, combustion tuning, optimization and use of a digital control system, boiler insulation, minimization of air filtration, boiler blowdown heat exchange, condensation return system, minimization of gas-side heat transfer surface deposits, and steam line maintenance.

iii. ***EU 60: 15.65 MMBtu/hr Fuel Gas (Dewpoint) Preheater***
Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of efficient burner design and good combustion, operating and maintenance practices constitute BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	Compliance Demonstration
60	GCOP	114.0 lb/MMBtu	Monitoring & Recordkeeping
		7,821 tpy	

Analysis: Of the fossil fuels considered, natural gas emits less CO_2 than its liquid and solid counterparts. Operating with a fuel other than natural gas would alter the design and purpose of the boiler, so this is not a technically feasible option. Furthermore, emissions of other pollutants, such as CO and NO_x, could potentially increase with the use of an alternative fuel, which would result in negative environmental impacts. GCOP includes efficient burner design, operating and maintenance practices, and good combustion practices.

iv. ***EU 61: 2.18 MW Diesel Emergency Generator;*** **and**
EU 62: 422 HP Diesel Emergency Fire Pump
Decision Summary: The Division determines the use of GCOP, including combustion design controls and usage limitations, constitutes BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	Compliance Demonstration
61 & 62	GCOP	N/A	N/A

Analysis: GCOP requires KU Brown to lower energy consumption which optimizes the engines' efficiency, reducing the fuel need and GHG emissions.

v. *EU 64: Turbine Circuit Breaker with 30-lb SF_6 Circuit*

Decision Summary: The Division determines the use of an AVO constitutes BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	Compliance Demonstration
64	AVO	Maximum Leak Rate = 0.5% SF_6	Leak detection system

Analysis: KU Brown identifies component type/design, leak inspections (LDAR or AVO), low-leaking components, and use of non-SF_6 circuit breakers as potential control techniques. Use of non-SF_6 insulating gas for the circuit breakers is not technically feasible, because the voltage required for the facility is too high. Implementation of an LDAR program is not economically feasible, as potential emissions are too low at 21.15 tpy of CO_2e. This PTE is based on the manufacturer's guarantee of a maximum 0.5% leak rate. The Division determines the manufacturer guarantee is not sufficient for BACT, so KU Brown is required to monitor and maintain records of detected leaks, noting any corrective actions taken.

vi. *EU 69: Natural Gas Piping Components*

Decision Summary: Consistent with the BACT evaluation conducted and submitted by KU Brown, the Division determines the use of AVO constitutes BACT for GHGs.

Emission Point	BACT	BACT Limit for GHGs	Compliance Demonstration
69	AVO	N/A	Recordkeeping of AVO inspections

Analysis: KU Brown identifies component type/design, leak inspections, and low-leaking components as potential BACT. KU Brown will incorporate low-leaking components into the design of their process. LDAR was determined to be cost prohibitive, so regular AVO inspections will be conducted.

III. Air Quality Impact Analysis:

A. Screening Methodology:

The incremental increases in ambient pollutant concentrations associated with the KU Brown NGCC project have been estimated through the use of a dispersion model (AERMOD) in its most recent version 24142 released November 2024. The submitted demonstration adheres to applicable guidelines in the United States Environmental Protection Agency (USEPA) *Guideline on Air Quality Models* (GAQM, 40 CFR part 51 Appendix W, Revised November 29, 2024, cited by reference in 401 KAR 51:017, Section 10), EPA's AERMOD Implementation Guide (November 2024), EPA's User's Guide for the AMS/EPA Regulatory Model – AERMOD (EPA-454/B-23-008, November 2024), EPA's *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (July 29, 2022), and follows the methodology presented in the Air Dispersion Modeling Protocol approved by the Division on April 25, 2025.

For NO_2 modeling, KU Brown uses the Tier 3 methodology to produce compliant modeling results, using the OLM approach in the modeling analysis. KU Brown uses published In-Stack Ration (ISR) data from EPA, the Electric Power Research Institute (EPRI), and the San Joaquin Valley Air Pollution Control District (SJVAPCD).

Unit	Fuel	ISR	Source
Unit 3 Boiler	Coal	0.1	EPA ISR Database (Max of Coal-Fired Boiler Data)
Unit 12 Gas Turbine	Natural Gas	0.5	EPRI Tale 3-5, Average ISR for All Sizes and Loads
Simple Cycle Turbines	Natural Gas	0.23	EPRI Table 3-6, Average ISR for All Sizes and Loads
Auxiliary Boiler/Fuel Gas Preheater	Natural Gas	0.1	SJVAPCD for Natural Gas-Fired Boilers
Emergency Generators	Diesel	0.2	SJVAPCD for Diesel ICE
Nearby Sources	Various	0.2	EPA NO_2 Clarification Memo (September 2014)

The following AERMOD selections were made:

1. Regulatory default options were chosen unless otherwise noted.
2. KU Brown determined that only 3.3% of the land within a 3 km radius is considered urban, so the option of "Rural" was chosen.
3. Direction-specific equivalent building dimensions used as input to simulate the impacts of downwash were calculated using the EPA-sanctioned Building Profile Input Program (BPIP-PRIME), version 04274.
4. Terrain elevations were considered using AERMAP version 24142, which generates base elevations above mean sea level of sources, buildings, and/or receptors as specified by the user. KU Brown used AERMAP for the project and all receptors to calculate the effect of terrain on each plume.

5. Meteorological data preprocessing was accomplished using the AERMET processor version 22112 along with nearby sets of NWS data from surface and upper air stations. There are 8 candidate first-order NWS surface meteorological observation stations and seven upper air stations within 150 km of KU Brown. The closest, Blue Grass Airport (KLEX) and Wilmington, OH (ILN), were selected for surface level and upper air data, respectively. The most recent data sets from KLEX and ILN, covering the 2019-2023 meteorological data period, are used in the dispersion modeling.
6. Locations are presented in Universal Transverse Mercator (UTM) coordinates. The datum for KU Brown is based on North American Datum 1983. All UTM coordinates reside within UTM Zone 16, which serves as the reference point for all model data, regional receptors, and sources.
7. Ground level concentrations were calculated from the fence line out to 10 km for the annual NO_2, 1- and 8-hour CO, annual and 24-hour PM_{10}, and the annual and 24-hour $PM_{2.5}$. For 1-hour NO_2, they were calculated from the fence line out to 50 km. A series of nested receptor grids (fence line, fine Cartesian, medium Cartesian, coarse, Cartesian, and very coarse Cartesian) were used in the Significant Analysis, PSD Increment modeling, and overall NAAQS modeling.
8. Emergency/Intermittent sources are excluded.
9. Regional source data was obtained from the Division.

The NGCC project will not cause any upstream or downstream emissions impacts at existing emission units, so the SIL modeling analysis only includes new emission units associated with the project. KU Brown conducted a load analysis for the new CT to determine the appropriate load scenario for inclusion in each of the modeling analyses. The worst-case load scenario for each pollutant and averaging period was utilized to evaluate against the SIL; if the SIL was exceeded by any load scenario, the receptor was determined significant and carried forward into the NAAQS analyses.

Significant Impact Levels (SILs)						
Pollutant	**Averaging Period**	**Modeled Concentration (µg/m³)**	**PSD SIL (µg/m³)**	**SIL Exceeded & Additional Modeling Required?**	**Significant Monitoring Concentration (µg/m³)**	**Significant Monitoring Concentration Exceeded?**
CO	1-hour	1,038	2,000	No	N/A	N/A
	8-hour	252	500	No	575	No
NO_2	1-hour	75.2	7.5	Yes	N/A	N/A
	Annual	1.6	1	Yes	14	No
PM_{10}	24-hour	8.9	5.0	Yes	10	No
	Annual	0.21	1.0	No	N/A	N/A
$PM_{2.5}$	24-hour	2.15	1.2	Yes	4	No
	Annual	0.19	0.13	Yes	N/A	N/A

Additional modeling is required for NO_2, PM_{10} (24-hour only), and $PM_{2.5}$. The radius of the Significant Impact Area (SIA) for NO_2 was determined to be 49.81 km and 0.86 km for the 1-hour and annual averaging periods, respectively. The radius of the SIA for PM_{10} was determined to be 1.12 km for the 24-hour averaging period. The radius of the SIA for $PM_{2.5}$ was determined to be 1.52 km and 1.28 km for the 24-hour and annual averaging periods, respectively. The analysis for $PM_{2.5}$ includes impacts from both primary and secondary $PM_{2.5}$ formation. Modeling is required to estimate the NAAQS and PSD Increment impacts of the NGCC Project, other existing emission units at KU Brown, and nearby regional inventory sources on a combined basis. For NAAQS dispersion modeling, background concentrations from nearby representative ambient monitors are also added to the total impacts of all sources.

B. <u>Background Concentrations</u>:

Representative background concentrations are added to the maximum predicted concentrations so that small sources that are not explicitly modeled are included in the NAAQS and KYAAQS assessment. Background concentrations are based on ambient monitoring data from sites with data for the required pollutants, period of data collection, adherence to Federal U.S. EPA QA/QC procedures, proximity, and representativeness (based on similar land use and geographical setting between KU Brown and the monitor site) for the three-year period between 2021 and 2023. KU Brown did not exclude any atypical smoke events (i.e. wildfires) from the $PM_{2.5}$ design value calculations due to the significant compliance margin provided by the model.

Site ID	Monitor Location	Pollutant	Averaging Period	Background Concentration Design Value	Basis of Design Value
21-111-0067	Louisville/Jefferson County, KY-IN	CO	8-hour	2,285.7 μg/m^3	2nd high concentration over 2022-2023 period
			1-hour	3,657.1 μg/m^3	
21-067-0012	Lexington-Fayette, Fayette County, KY	NO_2	Annual	11.3 μg/m^3	Highest value from 3-year period
			1-hour	75.2 μg/m^3	3-year average 98th percentile 1-hour average
21-113-0001	Lexington-Fayette, Jessamine County, KY	Ozone	8-hour	66 ppb[1]	3-year average of the annual 4th highest daily max 8-hour concentration
21-067-0012	Lexington-Fayette, Fayette County, KY	PM_{10}	24-hour	28.0 μg/m^3	4th high 24-hour concentration over 3-year period
21-199-0003	Somerset, Pulaski County, KY	$PM_{2.5}$	Annual	7.5 μg/m^3	Average monitor value from 3-year period
			24-hour	20.0 μg/m^3	3-year average 98th percentile 24-hour average

[1] Hourly varying ozone background concentration was used as input for Tier 3 NO_2 conversion option (OLM). Since the Jessamine County monitor only operates during ozone season, KU has used the Washington County monitor (Site ID: 21-229-9991) to supplement the Jessamine County monitor data during non-ozone season and for missing hours.

C. Secondary $PM_{2.5}$ 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 downwind secondary $PM_{2.5}$ formation, 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. KU Brown uses the U.S. EPA's Owen County hypothetical source in the Tier-1 modeling analysis, as this source has similar terrain and surrounding land use to KU Brown and is generally within the same air shed with similar atmospheric chemistry and secondary pollutant formation.

Averaging Period	Precursor	Modeled Emissions from Hypothetical Source (tpy)	Modeled Impact from Hypothetical Source (µg/m³)	Net Emissions Increase (tpy)	$PM_{2.5}$ Project Impact (µg/m³)	SIL (µg/m³)
24-hour	NO_x	500	0.050	169.2	0.017	
	SO_2	500	0.109	27.2	0.006	
	Total				0.023	1.2
Annual	NO_x	500	0.003	169.2	0.0011	
	SO_2	500	0.003	27.2	0.0002	
	Total				0.0012	0.13

The site-specific secondary $PM_{2.5}$ impact assessment demonstrates precursor emissions from the NGCC project will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS or PSD increment standard.

D. Class II NAAQS Analysis:

NAAQS analyses for NO_2, PM_{10}, and $PM_{2.5}$ were conducted. The NAAQS analysis results are as follows:

Pollutant	Averaging Period	NAAQS (µg/m³)	Maximum Impact (µg/m³)	Background Concentration (µg/m³)	Combined Maximum Impact (µg/m³)	Exceeds NAAQS?	Max KU Brown Contribution[6] (µg/m³)
NO_2	1-hour[1]	188	277.4	75.2	352.6	Yes	0.158
	Annual[2]	100	2.76	11.3	14.06	No	N/A
$PM_{2.5}$	24-hour[3]	35	4.71+0.0227	20.0	24.7	No	N/A
	Annual[4]	9	0.38+0.0012	7.5	7.9	No	N/A
PM_{10}	24-hour[5]	150	43.9	28.0	71.9	No	N/A

1. Evaluated the 5-year average 8th highest daily maximum 1-hour output
2. Evaluated the maximum modeled annual arithmetic mean impact from among the five years modeled
3. Evaluated the 5-year average 8th highest maximum 24-hour output
4. Evaluated average modeled annual arithmetic mean impact over the 5 years modeled
5. Evaluated the 5-year maximum 6th highest 24-hour output
6. From AERMOD contribution analysis results

The 1-hour average NO_2 modeled maximum impact exceeds the NAAQS, so KU Brown performed a NAAQS Cause or Contribute Analysis to demonstrate that KU Brown will not cause or contribute to an exceedance after the project. All receptors with 5-year average 8^{th} high daily maximum 1-hour concentrations higher than the NAAQS were identified using the plot file outputs from AERMOD. Source groups for KU Brown, all regional sources, and background are evaluated to determine the contribution from each of the source groups to the overall NAAQS impacts. The cause or contribute analyses for the 1-hour NO_2 NAAQS demonstrated that KU Brown and the NGCC project do not cause or contribute to any of the modeled exceedances.

E. Class II PSD Increment Analysis:

The maximum PSD Increment impacts correspond to steady-state conditions while firing the DBs and include startup and shutdown emissions for NO_2 annual, PM_{10} 24-hour, and $PM_{2.5}$ annual runs. The $PM_{2.5}$ modeling analysis accounts for both direct (AERMOD) and secondary (MERPs) $PM_{2.5}$ from the NGCC 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 that are fully operative that would consume increment.

Pollutant	Averaging Period	Year for Met. Data	Class II PSD Increment (μg/m³)	Maximum Impact (μg/m³)	Exceeds Increment?
NO_2	Annual[1]	Maximum of 5 years	25	2.23	No
$PM_{2.5}$	24-hour[2]		9	1.86	No
	Annual[3]		4	0.20	No
PM_{10}	24-hour[2]		30	15.49	No

1. Evaluated highest impacts for each year modeled
2. Evaluated the 2nd highest 24-hour average modeled impact over the 5 years modeled
3. Evaluated highest modeled annual arithmetic mean impact over the 5 years modeled

F. Class I Area Dispersion Modeling Analysis:

There are three Class I areas located within 300 km of KU Brown: Mammoth Cave (129 km), Great Smoky Mountains (247 km), and Joyce Kilmer-Slickrock (266 km). 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).

For PSD Increment consumption at affected Class I areas, KU Brown performed a Class I SIL evaluation. No further Class I PSD Increment analysis using long range transport modeling is required in cases where the significance analysis shows modeling results below the Class I SIL values.

Pollutant	Averaging Period	Class I SIL (μg/m³)
NO_2	Annual	0.10
PM_{10}	24-hour	0.32
	Annual	0.16
$PM_{2.5}$	24-hour	0.27
	Annual	0.03

For NO_2 Class I SIL evaluation, KU Brown applied the Class II area assessment Significance analysis model input parameters by placing rings of receptors at 48, 49, and 50 km, as recommended by GAQM. The results are all below the SIL threshold of 0.10 μg/m^3, with a maximum 1st high NO_2 impact over five years of 0.012 μg/m^3. using meteorological data from 2019 through 2023.

Given the stringency of the PM_{10} and $PM_{2.5}$ Class I SILs, the AERMOD screening approach can be overly conservative, especially for Class I areas beyond 100 km. Despite this, the primary $PM_{2.5}$ and PM_{10} Class I annual and 24-hour SIL results are all below the Class I SIL threshold.

Pollutant	Averaging Period	Distance from KU Brown (km)	SIL	Maximum 1st High Impact (μg/m^3)
Primary $PM_{2.5}$	24-hour	48	0.27	0.160
		49		0.153
		50		0.142
	Annual	48	0.03	0.006
		49		0.006
		50		0.006
Primary PM_{10}	24-hour	48	0.30	0.167
		49		0.157
		50		0.147
	Annual	48	0.20	0.006
		49		0.006
		50		0.006

Impacts from secondary $PM_{2.5}$ are considered in addition to primary $PM_{2.5}$ impacts. KU Brown utilizes the hypothetical source in Owen County to estimate secondary $PM_{2.5}$ concentrations by multiplying the project emissions increases for NO_x and SO_2 by the ratio of the modeled impact source over the modeled emission rate from the hypothetical source. The distance-dependent data for hypothetical sources was obtained from U.S. EPA's MERPs View Qlik website. The expected secondary $PM_{2.5}$ impacts at Mammoth Cave are combined with the modeled primary $PM_{2.5}$ project impact to compare the cumulative impact against the Class I SIL. The 24-hour cumulative $PM_{2.5}$ impact is 0.171 μg/m^3 and the annual cumulative $PM_{2.5}$ impact is 0.006 μg/m^3, both of which are below the Class I SILs of 0.27 μg/m^3 and 0.03 μg/m^3, respectively.

G. **Class I AQRV Analysis:**

Air Quality Related Values (AQRV), typically including visibility and surface deposition of sulfur and nitrogen, are considered by FLMs of Class I areas. 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 (in tpy) of SO_2, NO_x, PM_{10} and H_2SO_4 is divided by the distance from the source to the Class I area and 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 emissions for the proposed project for NO_x, PM_{10}, H_2SO_4, and SO_2 is 321.8 tpy.

Pollutant	NGCC Project's FLAG 2010 Approach Annual Emissions (tpy)
NO_x	168.9
PM_{10}	102.0
H_2SO_4	23.7
SO_2	27.2
Total	**321.8**

The three Class I areas within 300 km of the project all have a Q/D value less than 10. Therefore, this project is unlikely to trigger additional visibility concerns in these Class I areas. No further analysis is warranted.

Class I Area	Sum of Annualized Emissions, Q (tpy)	Minimum Distance from Site, D (km)	FLAG 2010 Q/D Approach (tpy/km)
Mammoth Cave	322	129	2.5
Great Smoky Mountains		247	1.3
Joyce Kilmer-Slickrock		266	1.2

H. <u>Additional Impacts Analysis</u>:

Three additional impacts analyses were performed: a growth analysis, a soil and vegetation analysis, and a visibility analysis. The project at KU Brown 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 EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (December 1980).

Pollutant	Averaging Period	Maximum Impact (μg/m^3)	Screening Concentrations for Exposure to Ambient Air Concentrations			Secondary NAAQS (μg/m^3)	Selected Soils and Vegetation Screening Threshold	Threshold Exceeded?
			Sensitive (μg/m^3)	Intermediate (μg/m^3)	Resistant (μg/m^3)			
NO_2	4-hour	393.5	3,760	6,400	16,920	N/A	3,760	No
	8-hour	359.1	3,760	7,520	15,040	N/A	3,760	No
	1-month	95.0	-	564	-	N/A	564	No
	Annual	14.1	-	94	-	100	94	No
CO	1-week	2,537	1,800,000	-	18,000,000	N/A	1,800,000	No
PM_{10}	24-hour	71.9	-	-	-	150	150	No
$PM_{2.5}$	24-hour	19.7	-	-	-	35	35	No
	Annual	7.3	-	-	-	15	15	No

KU Brown also conducted a visibility analysis at the closest potentially sensitive Class II area, Perryville Battlefield State Historic Site, using U.S. EPA VISCREEN following the guidelines in the *Workbook for Plume Visual Impact Screening and Analysis* (October 1992) to assess potential plume impairment. The plume had 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 3: Indirect Heat Exchanger				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
PM	40% opacity, except for 60% for 6 minutes in any 60 minutes and from building a new fire	401 KAR 61:015, Section 4(1)(c)	----	Compliance with consent decree
	0.157 lb/MMBtu (See Comment)	401 KAR 61:015, Section 4(1)(a) and 401 KAR 61:015, Section 4(2)	137.63 lb/ton uncontrolled (2016 EIS)	Performance Testing
	0.030 lb/MMBtu	Consent Decree, Paragraph 30A		
SO_2	5.15 lb/MMBtu	401 KAR 53:010 and 401 KAR 61:015, Section 5(1)	144.4 lb/ton uncontrolled (AP-42 1.1-3)	SO_2 CEMS
	2,300 tons/calendar year	Consent Decree, Paragraph 22		
	0.100 lb/MMBtu **OR** Removal Efficiency of not lower than 97%	Consent Decree, Paragraph 20		
NO_x	0.070 lb/MMBtu **OR** 0.080 lb/MMBtu if dispatch requires operation resulting in flue gas temperature where it is technically infeasible to continuously operate SCR	Consent Decree, Paragraphs 6 and 7	15 lb/ton uncontrolled (AP-42 1.1-3)	NO_x CEMS
SAM	473.1 tons/yr on 12-month rolling basis	Voluntary federally-enforceable limit to preclude BACT	6.625 lb/ton uncontrolled (2010 Stack Test)	Maintain a monthly and 12-month rolling total log on site
40 CFR 63, Subpart UUUUU Emission Limitations				
PM	Before July 6, 2027: 0.030 lb/MMBtu **OR** 0.30 lb/MWh (Gross)	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	137.63 lb/ton uncontrolled (2016 EIS)	Quarterly stack testing **OR** PM CEMS
	On or after July 6, 2027: 0.010 lb/MMBtu **OR** 0.10 lb/MWh (Gross)			
OR (On or after July 6, 2027, the permittee may only demonstrate compliance with the following total non-Hg HAP metals emission limit if requested and approved)				

Emission Unit 3: Indirect Heat Exchanger				
Total non-Hg HAP Metals	Before July 6, 2027: 0.000050 lb/MMBtu **OR** 0.50 lb/GWh	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	----	Quarterly stack testing
	On or after July 6, 2027: 0.000017 lb/MMBtu **OR** 0.17 lb/GWh			
OR All of these: (On or after July 6, 2027, the permittee may only demonstrate compliance with the following individual HAP metals emissions limits if requested and approved)				
Sb	Before July 6, 2027: 0.80 lb/TBtu **OR** 0.0080 lb/GWh	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	1.8×10^{-5} lb/ton controlled (AP-42 1.1-18)	Quarterly stack testing for each
	On or after July 6, 2027: 0.27 lb/TBtu **OR** 0.0027 lb/GWh			
As	Before July 6, 2027: 1.1 lb/TBtu **OR** 0.020 lb/GWh		4.1×10^{-4} lb/ton controlled (AP-42 1.1-18)	
	On or after July 6, 2027: 0.37 lb/TBtu **OR** 0.0067 lb/GWh			
Be	Before July 6, 2027: 0.20 lb/TBtu **OR** 0.0020 lb/GWh		2.1×10^{-5} lb/ton controlled (AP-42 1.1-18)	
	On or after July 6, 2027: 0.067 lb/TBtu **OR** 0.00067 lb/GWh			
Cd	Before July 6, 2027: 0.30 lb/TBtu **OR** 0.0030 lb/GWh		5.1×10^{-5} lb/ton controlled (AP-42 1.1-18)	
	On or after July 6, 2027: 0.10 lb/TBtu **OR** 0.0010 lb/GWh			

Emission Unit 3: Indirect Heat Exchanger				
Cr	Before July 6, 2027: 2.8 lb/TBtu **OR** 0.030 lb/GWh On or after July 6, 2027: 0.93 lb/TBtu **OR** 0.010 lb/GWh		$2.6x10^{-4}$ lb/ton controlled (AP-42 1.1-18)	
Co	Before July 6, 2027: 0.80 lb/TBtu **OR** 0.0080 lb/GWh On or after July 6, 2027: 0.27 lb/TBtu **OR** 0.0027 lb/GWh		$1.0x10^{-4}$ lb/ton controlled (AP-42 1.1-18)	
Pb	Before July 6, 2027: 1.2 lb/TBtu **OR** 0.020 lb/GWh On or after July 6, 2027: 0.40 lb/TBtu **OR** 0.0067 lb/GWh		$4.2x10^{-4}$ lb/ton controlled (AP-42 1.1-18)	
Mn	Before July 6, 2027: 4.0 lb/TBtu **OR** 0.050 lb/GWh On or after July 6, 2027: 1.3 lb/TBtu **OR** 0.017 lb/GWh		$4.9x10^{-4}$ lb/ton controlled (AP-42 1.1-18)	
Ni	Before July 6, 2027: 3.5 lb/TBtu **OR** 0.040 lb/GWh On or after July 6, 2027: 1.2 lb/TBtu **OR** 0.013 lb/GWh		$2.8x10^{-4}$ lb/ton controlled (AP-42 1.1-18)	

Emission Unit 3: Indirect Heat Exchanger				
Se	Before July 6, 2027: 5.0 lb/TBtu **OR** 0.060 lb/GWh On or after July 6, 2027: 1.7 lb/TBtu **OR** 0.020 lb/GWh		$1.3x10^{-3}$ lb/ton controlled (AP-42 1.1-18)	
AND				
HCl	0.0020 lb/MMBtu **OR** 0.020 lb/MWh	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	1.2 lb/ton (AP-42 1.1-15)	Quarterly stack testing **OR** HCl/HF CEMS
OR				
SO_2	0.20 lb/MMBtu **OR** 1.5 lb/MWh	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	144.4 lb/ton uncontrolled (AP-42 1.1-3)	SO_2 CEMS
AND				

Emission Unit 3: Indirect Heat Exchanger				
Hg	1.2 lb/TBtu, **OR** 0.013 lb/GWh	40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of 40 CFR part 63	8.3x10^{-5} lb/ton controlled (AP-42 1.1-18)	LEE Testing for 30 days with a sampling period consistent with that given in Section 5.2.1 of Appendix A to 40 CFR 63, Subpart UUUUU per Method 30B at Appendix A-8 to part 60 run **OR** Hg CEMS **OR** Sorbent Trap Monitoring
	OR			**OR**
	1.0 lb/TBtu OR 0.011 lb/GWh			LEE Testing for 90 days with a sampling period consistent with that given in Section 5.2.1 of Appendix A to 40 CFR 63, Subpart UUUUU per Method 30B at Appendix A-8 to part 60 run **OR** Hg CEMS **OR** Sorbent Trap Monitoring system only

Initial Construction Date: July 1971

Process Description:
Emission Unit 3 – Generating Unit 3 is a dry bottom, tangentially-fired coal-fired boiler design that uses Number 2 fuel oil for startups and stabilization. It has a heat input capacity of 5,300 MMBtu/hr and a net power output rating of approximately 433 MW. The following controls are utilized:

- Low NO_x Burners (LNB)
- Selective Catalytic Reduction (SCR) required by the Consent Decree for NO_x control
- Wet Flue Gas Desulfurization (FGD) required by the Consent Decree for SO_2 control
- Pulse Jet Fabric Filter required for PM control
- Dry Sorbent Injection for SAM control (using powdered activated carbon)
- Liquid Additives for Hg control

Applicable Regulations:
401 KAR 51:160, *NO_x requirements for large utility and industrial boilers*, In October 1998, 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 NO_x 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, 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.

On July 11, 2008, the United States Circuit Court of Appeals for the District of Columbia issued an opinion vacating and remanding CAIR to the U.S. EPA. A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the U.S. EPA finalized the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an August 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. CSAPR implementation is now in place and replaces requirements under EPA’s 2005 Clean Air Interstate Rule. The CSAPR Update Rule was published in October 2016.

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

401 KAR 61:015, *Existing indirect heat exchangers*, applicable to indirect heat exchangers having a heat input capacity of more than 1 MMBtu/hr commenced before August 17, 1971, for units with a capacity of more than 250 MMBtu/hr.

401 KAR 51:240, codifying **40 C.F.R. 97.401 through 97.435, Subpart AAAAA**, *Cross-State Air Pollution Rule (CSAPR) NO_x annual trading program*
401 KAR 51:250, codifying **40 C.F.R. 97.801 through 97.835, Subpart EEEEE**, *Cross-State Air Pollution Rule (CSAPR) NO_x ozone season group 2 trading program*
401 KAR 51:260, codifying **40 C.F.R. 97.601 through 97.635, Subpart CCCCC**, *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 63:002, Section 2(4)(yyyy), 40 C.F.R. 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,* applicable to a coal-fired EGU or and oil-fired EGU. A coal fired EGU is an electric utility steam generating unit (EGU) meeting the 40 CFR 63, Subpart UUUUU definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year. 40 CFR 63, Subpart UUUUU defines "fossil fuel-fired" as an EGU that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available. In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

40 CFR part 64, *Compliance Assurance Monitoring* (CAM), applicable to pollutant-specific emission units at a major source that are required to obtain a Title V permit and satisfy all of the following criteria:

- The unit is subject to an emission limitation or standard for the applicable regulated air pollutant, other than an emission limitation or standard proposed by the U.S. EPA Administrator after November 15, 1990 pursuant to Section 111 or 112 of the Clean Air Act;
- The unit uses a control device to achieve compliance with any such emission limitation or standard; and
- 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.

Unit 3 complies with CAM requirements for PM and SAM.

Additional Requirement:

Consent Decree filed on March 17, 2009 in U.S. District Court for the Eastern District of Kentucky, Central Division, Lexington, *United States of America v. Kentucky Utilities Company,* Civil Action No. 5:07-CV-0075-KSF ("Consent Decree" or "CD").

Comments:

AP-42, Chapter 1.1 Bituminous and Subbituminous Coal Combustion emission factors for pulverized coal, dry bottom, tangentially-fired boilers were used for all pollutants, except for Particulate Matter emissions (PM, PM_{10}, $PM_{2.5}$), which use a 2016 Performance Test result to establish emission factors.

In the event of an ID fan trip, Unit 3 has two 48" diameter vent pipes with butterfly valves ran to provide an alternate vent path to allow natural drafting for Unit 3. The valves are located between the existing PJFF and the Unit 3 ID fans. In that instance, the discharge from these two valves will duct to the existing Unit 2/Unit 3 combined stack.

The Consent Decree requires the use of Electrostatic Precipitators (ESP) to control PM. On February 18, 2013, KU submitted a minor revision application to install a PJFF with Dry Sorbent (DSI) Injection using Powdered Activated Carbon (PAC) for Hg capture to meet the MATS requirements. The removal of the ESP was necessary in order to have enough particulate in the gas stream to have proper filter cake loading on the PJFF. The Department of Justice and EPA determined this to be a "non-material change" to the CD.

When KU added the ESP (replaced the PM control device), it triggered a calculation of the 401 KAR 61:015 PM emission limitation under 401 KAR 61:015, Section 4(2). According to 401 KAR 50:020, Mercer County is a Priority II region for PM. The equation for Priority II region from Appendix A to 401 KAR 61:015 was used to interpolate the new PM emission limitation based on the total heat input capacity at the time Unit 3 was installed, or 8,293 MMBtu/hr. Additional changes in the PM control device does not necessitate an update to the 401 KAR 61:015 PM emission limitation.

Emission Unit 3: Indirect Heat Exchanger

During the PSD project review for the simple cycle combustion turbines (EUs 23-29), it was determined that Units 1-3 were causing a modeled violation of the SO_2 NAAQS. A lower SO_2 limit than what is required by 401 KAR 61:015 was accepted in order to demonstrate compliance with the SO_2 NAAQS.

As part of the CAM plan, the permit required testing to establish operating parameters for the sorbent injection system used to control emissions of SAM. Installation of a PM CEMS is utilized to ensure compliance with the PM emission limitations as part of CAM.

40 CFR 63, Subpart UUUUU requires quarterly compliance reports to replace semi-annual compliance reports beginning with calendar year 2024.

Pollutant	Controls	Efficiency	Installation Date
PM	Pulse Jet Fabric Filter	99.5%	2015
SO_2	Wet Flue Gas Desulfurization	93.2% (2010 Stack Test) 97% (Minimal Removal Eff Req)	2010
NO_x	Low- NO_x Burner	92.5% (Combined)	1992
	Selective Catalytic Reduction (SCR)		2012
SAM	Dry Sorbent Injection	93.2% (2010 Stack Test)	2013
	Wet Flue Gas Desulfurization		2010
Sb, As, Be, Cd, Cr, Co, Pb, Mn, Ni, Se	Dry-bottom, tangentially fired configuration (Inherent)	Control efficiency reflected in Emission Factor	1971
Hg	Dry-bottom, tangentially fired configuration (Inherent) **AND** Liquid Additives	Control efficiency reflected in Emission Factor	1971

Emission Units 23-29: Simple Cycle Combustion Turbines				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
NO_x	EU | Ppm by volume limit when burning: NG | #2 Oil 23 | 42 | 65 24 | 42 | 65 25 | 42 | 65 26 | 42 | 65 27 | 25 | 42 28 | 25 | 42 29 | 25 | NA	401 KAR 51:017 and 40 CFR 60.332(a) Note: Exempt when ice fog is deemed a traffic hazard [40 CFR 60.332(f)]	**EU 23 – EU 26**: *Distillate Oil* 24.36 lb/Mgal (Manufacturer), *Natural Gas* 115.92 lb/MMscf (Manufacturer); **EU 27 – EU 28**: *Distillate Oil* 27.3 lb/Mgal (Manufacturer), *Natural Gas* 99.54 lb/MMscf (Manufacturer); **EU 29**: *Natural Gas* 115.92 lb/MMscf (Manufacturer)	Performance testing at least once every 20 calendar quarters; CPMS for fuel consumption rate, hourly average heat input rate at ISO conditions, and the ratio of water or steam to fuel being fired
SO_2	EU | % Fuel Sulfur Content: w/ All CTs Op. | w/o All CTs Op. 23 | 0.26 | 0.30 24 | 0.26 | 0.30 25 | 0.26 | 0.30 26 | 0.26 | 0.30 27 | 0.23 | 0.30 28 | 0.23 | 0.30 29 | 0.26 | 0.30 EU | lbs/hr 23 | 444 24 | 444 25 | 444 26 | 444 27 | 666 28 | 666 29 | 444	401 KAR 51:017 and 40 CFR 60.333(b)	**EU 23 – EU 28**: *Distillate Oil* 7.02 lb/Mgal (AP-42 3.1-2a), *Natural Gas* 0.08 lb/MMscf (AP-42 3.1-2a); **EU 29**: *Natural Gas* 30.08 lb/MMscf (AP-42 3.1-2a)	Custom fuel monitoring plan for natural gas and distillate fuel oil maintained on site

Emission Units 23-29: Simple Cycle Combustion Turbines

CO	EU	lb/hr	tons/ 12-mo	401 KAR 51:017	**EU 23 – EU 28**: *Distillate Oil* 10.564 lb/Mgal (AP-42 3.3-1) *Natural Gas* 43 lb/MMscf (Manufacturer); **EU 29**: *Natural Gas* 43 lb/MMscf (Manufacturer)	Performance testing at least once every 20 calendar quarters; Calculate monthly emissions for a 12-month rolling total and report semi-annually (maintain log on site)
	23	75	93.8			
	24	75	93.8			
	25	75	93.8			
	26	75	93.8			
	27	112.5	140.63			
	28	112.5	140.63			
	29	75	93.8			
PM	EU	lb/hr	tons/ 12-mo	401 KAR 51:017	**EU 23 – EU 28**: *Distillate Oil* 1.668 lb/Mgal (AP-42 3.1-2a), *Natural Gas* 6.732 lb/MMscf (AP-42 3.1-2a); **EU 29**: *Natural Gas* 6.732 lb/MMscf (AP-42 3.1-2a)	Performance testing at least once every 20 calendar quarters; Calculate monthly emissions for a 12-month rolling total and report semi-annually (maintain log on site)
	23	67	83.8			
	24	67	83.8			
	25	67	83.8			
	26	67	83.8			
	27	100.5	125.63			
	28	100.5	125.63			
	29	67	83.8			
VOC	EU	lb/hr	tons/ 12-mo	401 KAR 51:017	**EU 23 – EU 28**: *Distillate Oil* 0.057 lb/Mgal (AP-42 3.1-2a), *Natural Gas* 2.142 lb/MMscf (AP-42 3.1-2a); **EU 29**: *Natural Gas* 2.142 lb/MMscf (AP-42 3.1-2a)	Performance testing at least once every 20 calendar quarters; Calculate monthly emissions for a 12-month rolling total and report semi-annually (maintain log on site)
	23	20.4	25.5			
	24	20.4	25.5			
	25	20.4	25.5			
	26	20.4	25.5			
	27	30.6	38.25			
	28	30.6	38.25			
	29	20.4	25.5			
Be	EU	lb/hr	tons/ 12-mo	401 KAR 51:017	**EU 23 – EU 28**: *Distillate Oil* $4.309x10^{-5}$ lb/MMscf (AP-42 3.1-5)	*Distillate Oil:* Performance testing at least once every 20 calendar quarters; Fuel monitoring assuming all Be in fuel is emitted; Calculate monthly emissions for a 12-month rolling total and report semi-annually (maintain log on site) *Natural Gas*: Compliance assumed
	23	3.37 E-3	4.21 E-3			
	24	3.37 E-3	4.21 E-3			
	25	3.37 E-3	4.21 E-3			
	26	3.37 E-3	4.21 E-3			
	27	5.057 E-3	6.35 E-3			
	28	5.057 E-3	6.35 E-3			
	29	3.37 E-3	4.21 E-3			

Emission Units 23-29: Simple Cycle Combustion Turbines

Initial Construction Date: Emission Unit 23: November 1995; Emission Unit 24: December 1995; Emission Unit 25: March 1996; Emission Unit 26: May 1996; Emission Unit 27: August 1999; Emission Unit 28: August 1999; Emission Unit 29: June 2001

Process Description:
Seven simple cycle combustion turbines, each with their own stack, operated to provide peaking power.

Emission Unit	Description	Maximum Continuous Rating	Fuel	Control Equipment
23	Combustion Turbine (Unit 9), Model ABB GT 11N2	1,368 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil; (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
24	Combustion Turbine (Unit 10) Model ABB GT 11N2	1,368 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil (Secondary)*; Distillate Fuel Oil (Emergency)	Water injection
25	Combustion Turbine (Unit 8) Model ABB GT 11N2	1,368 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil (Secondary)*; Distillate Fuel Oil (Emergency)	Water injection
26	Combustion Turbine (Unit 11) Model ABB GT 11N2	1,368 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil (Secondary)*; Distillate Fuel Oil (Emergency)	Water injection
27	Combustion Turbine (Unit 6), Model ABB GT 24	1,678 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil (Secondary)*; Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
28	Combustion Turbine (Unit 7) Model ABB GT 24	1,678 MMBtu/hr	Natural Gas (Primary); Distillate Fuel Oil (Secondary)*; Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
29	Combustion Turbine (Unit 5) Model ABB GT 11N2	1,368 MMBtu/hr	Natural Gas	Water injection

* A notification shall be submitted prior to the use of distillate fuel oil as a secondary fuel for non-emergency usage.

Applicable Regulation:
401 KAR 51:017, *Prevention of significant deterioration of air quality,* applicable to the 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.

401 KAR 51:240, codifying **40 C.F.R. 97.401 through 97.435, Subpart AAAAA**, *Cross-State Air Pollution Rule (CSAPR) NO_x annual trading program*

401 KAR 51:250, codifying **40 C.F.R. 97.801 through 97.835, Subpart EEEEE**, *Cross-State Air Pollution Rule (CSAPR) NO_x ozone season group 2 trading program*

Emission Units 23-29: Simple Cycle Combustion Turbines

401 KAR 51:260, codifying **40 C.F.R. 97.601 through 97.635, Subpart CCCCC**, *Cross-State Air Pollution Rule (CSAPR) SO_2 group 1 trading program* applicable to stationary, fossil-fuel-fired combustion turbines serving at any time, on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

401 KAR 52:060, *Acid rain permits,* incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78**, applicable to new utility units as set forth under 40 CFR 72.6.

401 KAR 60:005, Section 2(2)(pp), 40 C.F.R. 60.330 through 60.335 **(Subpart GG**) *Standards of Performance for Stationary Gas Turbines*, applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the lower heating value of the fuel fired that commenced construction, modification, or reconstruction after October 3, 1977. These units do not meet any of the exemptions listed.

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* (Note: This regulation applies, but these are existing units [40 CFR 63.6090(a)(1)], and they do not have to meet the requirements of this regulation. [40 CFR 63.6090(b)(4)])

40 CFR 75, Appendix E, *Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*, may be used in lieu of a continuous NO_x emission monitoring system for determining the average NO_x emission rate and hourly NO_x rate from gas-fired peaking units. If the unit is not operated as a peaking unit, a NO_x CEMS needs to be installed by December 31 of the following calendar year.

Comments:
These emission units are exempt from CAM applicability under 40 CFR 64.2(b)(2) for the following reasons:

1. The units are exempt from all monitoring requirements in 40 CFR part 75 as long as the unit operates as a peaking unit;
2. The units are operated for the sole purpose of providing electricity during periods of peak electrical demand or emergency situations; and
3. The actual emissions from these units, based on the average annual emissions over calendar years 2023, 2024, and 2025, are less than 50% of the amount in tpy required for a source to be classified as a major source. The Division does not expect the three-year annual average emissions from these units to exceed this 50% of major source threshold.

The NO_x emission factors for natural gas and distillate oil combustion were obtained directly from the equipment manufacturer. The CO emission factor for distillate oil combustion was also sourced from manufacturer-provided data. Greenhouse gas emission factors were derived using values specified in 40 CFR 98, Tables C-1 and C-2. All remaining emission factors were referenced from AP-42, Chapter 3.1 Stationary Gas Turbines.

Additional testing for CO, PM, VOC and beryllium has been added to these units (once every 20 calendar quarters) to demonstrate compliance with BACT limits. These units are considered in compliance with the beryllium (Be) limits when burning natural gas. As an alternative to conducting beryllium stack testing for fuel oil, fuel supplier certification or fuel sampling may be used assuming all Be in the fuel is emitted as Be.

Emission Units 23-29: Simple Cycle Combustion Turbines
Each turbine has a fuel sulfur content limit and a SO_2 emission rate limit. The Division has determined that demonstrating compliance with the fuel sulfur content limits will ensure the turbines are in compliance with the SO_2 emission rate limits. This determination was made using the fuel sulfur content limits and assuming all fuel sulfur is emitted as SO_2. Emission Units 23-26 and 29 will have the potential to emit 416 lb/hr of SO_2 using a sulfur content of 0.30% and Emission Units 27 and 28 will have the potential to emit 442 lb/hr of SO_2 using a sulfur content of 0.26%. The emission rate limits are 444 lb/hr and 666 lb/hr, respectively. <u>Emissions Monitoring</u> Emissions are monitored using the fuel consumption rate, hourly average heat input rate at ISO conditions, and ratio of water to fuel being fired for each unit. Additionally, NO_x and SO_2 emissions are monitored according to the methodologies in Appendices D and E to 40 CFR 75. Based on the application submitted under APE20200004, restricting the use of distillate fuel oil (emergency) to only time natural gas is unavailable, the permittee is not required to conduct performance testing every 20 calendar quarters while burning distillate fuel oil (emergency). EU 29 (CT 5) accepted a maximum heat input of 1,368 MMBtu/hr but has a capacity of 1,438 MMBtu/hr. EU 23 – EU 26 & EU 29: Water Injection; 65% NO_x control efficiency; EU 27 – EU 28: Water Injection when burning oil, low NO_x burners when burning natural gas; 65% control efficiency

Emission Unit 58: Combined Cycle Combustion Turbine with HRSG				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
CO	2.0 ppmvd at 15% O_2 on a 24-operating hour rolling average basis[a]	401 KAR 51:017 BACT	48.232 lb/MMscf (Facility Requirement)	CO CEMS monitoring, recordkeeping and reporting
	134.6 tpy on a 12-month rolling basis[b]			
NO_x	2.0 ppmvd at 15% O_2 on a 24-operating hour rolling average basis[a]	401 KAR 51:017 BACT	79.219 lb/MMscf (Facility Requirement)	NO_x CEMS, testing, monitoring, recordkeeping and reporting
	151.4 tpy on a 12-month rolling basis[b]			
	Utilization > 45%: 5 ppm at 15% O_2 or 7.9 ng/J (0.018 lb/MMBtu) Both on a 4-operating hour rolling average basis	40 CFR 60, Subpart KKKKa, Table 1[e]		
$PM/PM_{10}/PM_{2.5}$[f]	0.005 lb/MMBtu on a 3-hour average[b]	401 KAR 51:017	5.256 lb/MMscf (Vendor Estimate)	Performance Testing
	98.9 tpy on a 12-month rolling average basis[b]			
	0.10 lb/MMBtu[c]	401 KAR 59:015, Section 4(1)(b)[c]		Compliance assumed while combusting natural gas
	20% Opacity, except 27% for 6 min during any 60 min, and during building a new fire[c]	401 KAR 59:015, Section 4(2)[c]		
VOC	1.0 ppmvd (as CH_4) at 15% O_2 without DBs on a 3-hour average[a]	401 KAR 51:017	5.525 lb/MMscf (Facility Requirement)	Performance Testing, monitoring, recordkeeping and reporting
	2.0 ppmvd (as CH_4) at 15% O_2 with DBs on a 3-hour average[a]			
	64.6 tpy on a 12-month rolling average basis[b]			
CO_2	925 lb/MWh (gross) without DBs on a 12-month rolling average basis[b]	401 KAR 51:017	120,019 lb/MMscf (40 CFR 98, TBL C-1)	CO_2 CEMS, GCOP, monitoring, recordkeeping, and reporting
	815 lb/MWh (gross) with DBs on a 12-month rolling average basis[b]			

Emission Unit 58: Combined Cycle Combustion Turbine with HRSG				
	Before Jan. 2032: 800-1,250 lb/MWh (gross)	Table 1 to 40 CFR 60, Subpart TTTTa		
	After Dec. 2031: 100-150 lb/MWh (gross)			
CO_2e[d]	2,261,306 tpy on a 12-month rolling average basis[b]	401 KAR 51:017	CH_4: 24.88 lb/MMscf N_2O: 3.62 lb/MMscf (40 CFR 98, TBL C-2)	
SO_2	26 ng/J (0.060 lb/MMBtu)	40 CFR 60.4330(a)(2)	1.427 lb/MMscf (Pipeline Specification Conversion)	Fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract
	0.8 lb/MMBtu[c]	401 KAR 59:015, Section 5(1)(b)1.		Compliance assumed while combusting natural gas
Formalde-hyde	91 ppbvd at 15% O_2, except during startup	Table 1, Item 1 to 40 CFR 63, Subpart YYYY	0.655 lb/MMscf (AP-42 3.1)	Performance Testing, recordkeeping and reporting

[a] Excluding startups and shutdowns
[b] Including startups and shutdowns
[c] HRSG Only Requirement
[d] CO_2e utilizes Global Warming Potentials of 28 and 265 for CH_4 and N_2O, respectively
[e] See Table 1 to 40 CFR 60, Subpart KKKKa for optional output-based standards.
[f] All PM assumed to be less than 2.5 micrometers in diameter.

Projected Construction Date: Proposed June 2026

Process Description:
Combined cycle operation consisting of one natural gas-fired lean premix combustion turbine (CT) and one steam turbine. The heat from the combustion gases created by the CT is used in a heat recovery steam generator (HRSG) to produce steam from water in a closed loop system. The HRSG is equipped with natural gas-fired duct burners (DBs) to assist in the production of steam, as needed, and this steam is used in the steam turbine. Electricity is generated from both the CT and the steam turbine. This unit will utilize inlet evaporative cooling and dry low-NO_x combustors in the CT and low-NO_x burners in the HRSG.

Facility Name: Unit 12
Make/Model: GE 7HA.03 Gas Turbine (GT)

Emission Unit 58: Combined Cycle Combustion Turbine with HRSG

Maximum Continuous Rating:	4,895 MMBtu/hr for the GT 4,525 MMBtu/hr (HHV) when firing DBs* 3,969 MMBtu/hr (HHV) when not firing DBs* *maximum simulated heat input capacity across NGCC system taking into account seasonal variation for baseload operation
Maximum Power Output:	681 MWh (gross)
Fuel:	Natural Gas
Controls:	Selective Catalytic Reduction (SCR) Dry Low NO_x Combustors (DLN) Oxidation Catalyst

Applicable Regulations:

401 KAR 51:017, *Prevention of significant deterioration of air quality* (CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, and CO_2e), applicable to the construction of 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). Sections 8 to 16 apply to a major modification of an existing major stationary source.

401 KAR 51:160, *NO_x requirements for large utility and industrial boilers*, applicable to NO_x budget units that are electric generating units or industrial boilers or turbines, except as provided under Section 2 (Exemptions) of 401 KAR 51:160.

401 KAR 51:240, codifying **40 C.F.R. 97.401 through 97.435, Subpart AAAAA**, *Cross-State Air Pollution Rule (CSAPR) NO_x annual trading program*
401 KAR 51:250, codifying **40 C.F.R. 97.801 through 97.835, Subpart EEEEE**, *Cross-State Air Pollution Rule (CSAPR) NO_x ozone season group 2 trading program*
401 KAR 51:260, codifying **40 C.F.R. 97.601 through 97.635, Subpart CCCCC**, *Cross-State Air Pollution Rule (CSAPR) SO_2 group 1 trading program*, applicable to any stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale.

401 KAR 52:060, *Acid rain permits*, applicable to new utility units that serves a generator to produce electricity for sale; the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the date on which the unit commences operation. The application was received on 3/27/2025 so this unit cannot commence operation until 3/27/2027 or later. This unit is subject to the SO_2 provisions but not the NO_x provisions.

401 KAR 60:005, Section 2(2)(jjjj), 40 C.F.R. 60.5508 to 60.5580, Tables 1 to 3 (**Subpart TTTTa**), *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, applicable to any stationary combustion turbine that commences construction after May 23, 2023 that has a base load rating greater than 250 MMBtu/hr of fossil fuel and serves a generator (or generators) capable of selling greater than 25 MW of electricity to a utility power distribution system.

401 KAR 63:002, Section 2(4)(dddd), 40 C.F.R. 63.6080 to 63.6175, Tables 1 to 7 (**Subpart YYYY**), *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, applicable to stationary combustion turbines located at a major source of HAP emissions. Duct burners and waste heat recovery units are considered steam generating units and are not covered under 40 CFR 63, Subpart YYYY. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners

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in operation.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub- components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by 40 CFR 63, Subpart YYYY include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to 40 CFR 63, Subpart YYYY do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

40 CFR 60, Subpart KKKKa, *Standards of Performance for Stationary Combustion Turbines,* applicable to a stationary combustion turbine that commenced construction after December 13, 2024, and that has a base load rating equal to or greater than 10 MMBtu/hr. Any additional heat input from DBs used with HRSG units or fuel preheaters is not included in the heat input value used to determine the applicability. However, 40 CFR 60, Subpart KKKKa does apply to emissions from any associated HRSG and DB(s) that are associated with a CT subject to 40 CFR 60, Subpart KKKKa.

40 CFR part 64, *Compliance Assurance Monitoring*, applicable to VOC emissions only. This unit uses a control device to achieve compliance with emission limits for NO_x, CO, Formaldehyde, and VOC, all of which have potential pre-control device emissions greater than 100% of the amount required for the source to be classified as a major source.

- The unit is subject to two NO_x emission limitations: 40 CFR 60, Subpart KKKKa and a BACT limit. 40 CFR 60, Subpart KKKKa was promulgated after November 15, 1990, and the facility will demonstrate continuous compliance with the NO_x BACT limit through the use of NO_x CEMS. Therefore, the unit is exempt from CAM for NO_x under 40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi), respectively.
- The unit is subject to a CO BACT emission limitation and will demonstrate continuous compliance through the use of a CO CEMS. Therefore, the unit is exempt from CAM for CO under 40 CFR 64.2(b)(1)(vi).
- The unit is subject to emission limitations for Formaldehyde under 40 CFR 63, Subpart YYYY, which was promulgated after November 15, 1990. Therefore, the unit is exempt from CAM for formaldehyde under 40 CFR 64.2(b)(1)(i).

The unit is a large pollutant-specific emission unit for VOC, so a CAM plan will be submitted upon renewal of the Title V permit.

Non-Applicable Regulation:

401 KAR 60:005, Section 2(2)(b), 40 C.F.R. 60.40Da through 60.52Da (**Subpart Da**), *Standards of Performance for Electric Utility Steam Generating Units*, not applicable to duct burners 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.

Additional Requirement Specifically For HRSG:

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401 KAR 59:015, *New indirect heat exchangers*, applicable to indirect heat exchangers (a piece of equipment, apparatus, or contrivance used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion) having a heat input capacity greater than 1 MMBtu/hr commenced on or after August 17, 1971.

Comments:
BACT
CO and VOC: Oxidation catalyst & GCOP
NO_x: SCR, DLN & GCOP
$PM/PM_{10}/PM_{2.5}$: Inlet air filters, low sulfur fuel & GCOP
H_2SO_4: Low sulfur fuel & GCOP
CO_2e: GCOP

The Maximum Continuous Rating (MCR) of the gas turbine (GT) itself, disregarding limitations from the combined-cycle system, is 4,895 MMBtu/hr per the GT vendor. When considering seasonal variances in conjunction with the full combined-cycle system (i.e., the GT and the steam generator), the MCR across the combined-cycle system is lower. The hourly design rate utilizes the lower MCRs and converts them using a site-specific natural gas HHV of 1,053 Btu/scf.

Potential to emit (PTE) calculations for each pollutant considers the highest of the following scenarios:

1. 8,760 hours at steady-state in "fired" mode (no startups or shutdowns);
2. 8,760 hours at steady-state in "unfired" mode (no startups or shutdowns)); and
3. 7,470 hours in "fired" mode plus worst-case startup and shutdown emissions.

"Fired" mode is when the duct burners are operating and firing natural gas. Conversely, "unfired" mode is when the duct burners are <u>not</u> operating. For all pollutants except CO, VOC, and NO_x, scenario 1 is used for PTE calculations. Scenario 3 is used for CO, VOC, and NO_x, as emissions during startups and shutdowns assumes 0% control efficiency from the SCR and oxidation catalyst.

The maximum number of startups and subsequent shutdowns each year is 185, assuming 10 cold startups, 50 warm startups, and 125 hot startups. A cold startup takes 73-280 minutes to ramp up and is preceded by over 72 hours of shutdown. Warm startups take 63-89 minutes to ramp up and are preceded by 8-72 hours of shutdown. Hot startups take 33-54 minutes to ramp up and are preceded by 0-8 hours of shutdown. Shutdowns take between 12 and 21 minutes to occur. To conservatively calculate the hours at steady-state for scenario 3, the maximum number of startup and shutdown events with the minimum number of hours between events and minimal time to ramp up to steady-state or shutdown from steady-state is used. Maximum uncontrolled emissions of pollutants during each type of startup (cold, warm, or hot) and shutdown event were supplied by the vendor.

For CO, VOC, and NO_x potential emission calculations, the vendor guaranteed post-control steady-state concentration (ppmvd) and emission rate (lb/hr) is used to calculate an uncontrolled emission factor assuming 90% control for NO_x and CO and 50% control for VOC. The dry F-factor is calculated by the vendor using Equations 19-13 through 19-15 according to Appendix A-7 of 40 CFR part 60.

The vendor also supplied an estimated maximum emission rate for H_2SO_4, NH_3, formaldehyde (to meet 40 CFR 63, Subpart YYYY requirements), and $PM/PM_{10}/PM_{2.5}$.

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- H_2SO_4 considers several factors, including DB operation and oxidation within the SCR and oxidation catalyst.
- NH_3 is from ammonia slip in the SCR.
- All PM is assumed to be less than 2.5 micrometers in mean diameter.

The maximum sulfur content of 0.5 gr/100scf is used to calculate potential SO_2 by assuming all fuel sulfur is converted to SO_2 and converted using 7,000 gr/lb and the molecular weight ratio of SO_2 to S. Greenhouse gas emissions are calculated using Tables C-1 and C-2 of 40 CFR 98, Subpart C and the global warming potentials from 40 CFR 98, Subpart A, updated in the final rule published on April 25, 2024 and effective January 1, 2025. HAP PTE calculations utilize emission factors from AP-42, Section 3.1 for the GT and Section 1.4 for the DBs.

As of the issuance of Permit V-26-036, *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*.

401 KAR 60:005, Section 2(2)(pp), 40 C.F.R. 60.330 through 60.335 (**Subpart GG**), *Standards of Performance for Stationary Gas Turbines,* does not regulate units subject to 40 CFR 60, Subpart KKKKa.

Emission Units 55-57: Natural Gas Process Heaters				
Pollutant	**Emission Limit**	**Regulation**	**Emission Factor Used and Basis**	**Control Device, Efficiency and Basis**
PM	0.10 lb/MMBtu	401 KAR 59:015, Section 4(1)(b)	7.6 lb/MMscf (AP-42 1.4-2)	These units are assumed to be in compliance while burning natural gas
	20% Opacity	401 KAR 59:015, Section 4(2)		
SO_2	0.8 lb/MMBtu	401 KAR 59:015, Section 5(1)(b)1.	0.6 lb/MMscf (AP-42 1.4-2)/	

Initial Construction Date: EU 55: 2003; EUs 56 & 57: 2000

Project Description:
EU 55 (CT NG-05): 2.4 MMBTU/hr NG Preheater NATCO S832-205D
EU 56 (CT NG-06): 7.0 MMBTU/hr NG Preheater ETI Custom Built
EU 57 (CT NG-07): 7.0 MMBTU/hr NG Preheater ETI Custom Built

Applicable Regulations:
401 KAR 59:015, *New indirect heat exchangers,* applicable to indirect heat exchangers with a heat input capacity greater than 1 MMBtu/hr commenced on or after August 17, 1971.

401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 63.7480 to 63.7575, Tables 1 to 13 (**Subpart DDDDD**), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* , applicable to industrial boilers or process heaters located at a major source of HAPs.

Comments:
The emission factors for this unit were referenced from AP-42, Chapter 1.4 Natural Gas Combustion for small boilers (<100 MMBtu/hr).

The energy assessment required by 40 CFR 63, Subpart DDDDD was completed on 9/12/2019 by Trinity.

The most recent tune-up conducted on all boilers was 7/18/2024. EU 55 has a heat input capacity of less than 5 MMBtu/hr and is therefore subject to 40 CFR 63.7540(a)(12) to conduct a tune-up every 5 years. The next tune-up is due July 2029. EUs 56 and 57 have heat input capacities less than 10 MMBtu/hr but greater than 5 MMBtu/hr and is therefore subject to 40 CFR 63.7540(a)(11) and required to conduct biennial tune-ups. The next tune-up is due July 2026.

Emission Unit 59: Natural Gas Combustion Unit Supporting NGCC System: Auxiliary Boiler				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
CO	0.037 lb/MMBtu	401 KAR 51:017 (BACT)	38.6 lb/MMscf (Vendor Guarantee)	Performance Testing; NG Combustion[a]; Operate & maintain LNBs & FGR; GCOP
	7.0 tpy			
NO_x	0.036 lb/MMBtu		38.3 lb/MMscf (Vendor Guarantee)	
	7.0 tpy			
VOC	0.0052 lb/MMBtu		5.5 lb/MMscf (Vendor Guarantee)	
	1.0 tpy			
CO_2e[b]	114.0 lb/MMBtu	401 KAR 51:017 (BACT)	CO_2: 120,019 lb/MMscf CH_4: 2.26 lb/MMscf N_2O: 0.226 lb/MMscf (40 CFR 98, Subpart C)	NG Combustion[a]; GCOP
	21,797 tpy			
$PM/PM_{10}/PM_{2.5}$ (filterable + condensable)	0.0070 lb/MMBtu	401 KAR 51:017 (BACT)	7.37 lb/MMscf (Vendor Guarantee)	Performance Testing; NG Combustion[a]; GCOP
	1.3 tpy			
PM	0.1 lb/MMBtu	401 KAR 59:015, Section 4(1)(b)		Compliance assumed while combusting NG
	20% opacity	401 KAR 59:015, Section 4(2)		
SO_2	0.8 lb/MMBtu	401 KAR 59:015, Section 5(1)(b)1.	1.43 lb/MMscf (Natural Gas Pipeline Conversion)	

[a] Combust only pipeline quality NG with sulfur content of 0.5 grains per 100 dry standard cubic feet or less for a maximum of 4,000 hours per 12-month rolling year.
[b] CO_2e utilizes Global Warming Potentials of 28 and 265 for CH_4 and N_2O, respectively.

Initial Construction Date: Proposed June 2026

Process Description:
95.52 MMBtu/hr Auxiliary Boiler with Low NO_x Burners (LNB) and Flue Gas Recirculation (FGR)
- Provide HRSG freeze protection for EU 58 (only required with the unit offline in cold weather conditions)
- Provide sparging steam to the HRSG and condenser, as well as seal steam for the steam turbine, under warm or cold start conditions. EU 59 can be taken offline once EU 58 is operating at steady-state and the HRSG starts providing auxiliary steam.
- Expected to operate at 25% utilization or less of periods when EU 58 is active.

Emission Unit 59: Natural Gas Combustion Unit Supporting NGCC System: Auxiliary Boiler

Applicable Regulations:

401 KAR 51:017, *Prevention of significant deterioration of air quality* (CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, and CO_2e), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

401 KAR 59:015, *New indirect heat exchangers*, 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*, 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 MW (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 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*, applicable to industrial boilers or process heaters located at a major source of HAPs.

Comments:

The hourly design rate is converted from MMBtu/hr to MMscf/hr using the site-specific HHV of natural gas, 1,053 Btu/scf. KU requires a vendor guarantee concentration of 35 ppmv NO_x at 0% O_2 and 58 ppmv CO at 0% O_2, converted to lb/MMscf utilizing the molecular weights (MW), molar volume of a gas at 528 °R and 1 atm, the dry F factor for natural gas (8,710 dscf/MMBtu) from Table 19-2 in Appendix A-7 to 40 CFR part 60, and the site-specific HHV of natural gas.

For VOC and PM/PM_{10}/$PM_{2.5}$ emissions, the vendor estimates emissions of 0.008 lb/MMBtu and 0.007 lb/MMBtu, respectively. The maximum sulfur content of 0.5 gr/100scf is used to calculate potential SO_2 by assuming all 7,000 gr/lb is converted to SO_2 and converted using the molecular weight ratio of SO_2 to S. It's further assumed that 5% of the SO_2 is converted to SO_3, of which 100% is assumed to form H_2SO_4.

Greenhouse gas emission factors are derived using values specified in 40 CFR 98, Subpart C, Tables C-1 and C-2. The global warming potentials used to calculate CO_2e are from Table A-1 in 40 CFR 98, Subpart A, updated in the final rule published April 25, 2024 and effective January 1, 2025. HAP emission factors are referenced from AP-42, Chapter 1.4 Natural Gas Combustion in the absence of unit-specific data.

Limited to 4,000 hours of operation, based on a 12-month rolling total.

The permittee shall monitor and maintain records of natural gas usage (in MMscf) on a monthly basis and hours of operation on a monthly and 12-month rolling total basis.

The first annual tune-up shall be performed within 13 months of the initial startup of the boiler.

Emission Unit 60: Natural Gas Combustion Unit Supporting NGCC System: Dewpoint Heater				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
CO	0.037 lb/MMBtu	401 KAR 51:017 (BACT)	38.6 lb/MMscf (Vendor Guarantee)	Performance Testing; Pipeline Quality NG Combustion; Operate & maintain LNBs; GCOP
	2.5 tpy			
NO_x	0.036 lb/MMBtu		38.3 lb/MMscf (Vendor Guarantee)	
	2.5 tpy			
VOC	0.008 lb/MMBtu		8.42 lb/MMscf (Vendor Guarantee)	
	0.5 tpy			
CO_2e	114.0 lb/MMBtu		CO_2: 120,019 lb/MMscf CH_4: 2.26 lb/MMscf N_2O: 0.226 lb/MMscf (40 CFR 98, Subpart C)	
	7,821 tpy			
$PM/PM_{10}/PM_{2.5}$ (filterable + condensable)	0.007 lb/MMBtu		7.37 lb/MMscf (Vendor Guarantee)	
	0.5 tpy			
PM	0.1 lb/MMBtu	401 KAR 59:015, Section 4(1)(b)		Compliance assumed while combusting NG
	20% opacity	401 KAR 59:015, Section 4(2)		
SO_2	0.8 lb/MMBtu	401 KAR 59:015, Section 5(1)(b)1.	1.43 lb/MMscf (Natural Gas Pipeline Conversion)	

Initial Construction Date: Proposed June 2026

Process Description:
15.65 MMBtu/hr Fuel Gas (Dewpoint) Heater with LNB used to heat the pipeline NG prior to introduction to the NGCC unit (EU 58).

Applicable Regulations:
401 KAR 51:017, *Prevention of significant deterioration of air quality* (CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, and CO_2e), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

401 KAR 59:015, *New indirect heat exchangers*, 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*, applicable to each

Emission Unit 60: Natural Gas Combustion Unit Supporting NGCC System: Dewpoint Heater

steam generating unit for which construction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 MW (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 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***,** applicable to industrial boilers or process heaters located at a major source of HAPs.

Comments:
The hourly design rate is converted from MMBtu/hr to MMscf/hr using the site-specific HHV of natural gas, 1,053 Btu/scf. KU requires a vendor guarantee concentration of 35 ppmv NO_x at 0% O_2 and 58 ppmv CO at 0% O_2, converted to lb/MMscf utilizing the molecular weights (MW), molar volume of a gas at 528 °R and 1 atm, the dry F factor for natural gas (8,710 dsf/MMBtu) from Table 19-2 in Appendix A-7 to 40 CFR part 60, and the site-specific HHV of natural gas.

For VOC and $PM/PM_{10}/PM_{2.5}$ emissions, the vendor estimates emissions of 0.008 lb/MMBtu and 0.007 lb/MMBtu, respectively. The maximum sulfur content of 0.5 gr/100scf is used to calculate potential SO_2 by assuming all 7,000 gr/lb is converted to SO_2 and converted using the molecular weight ratio of SO_2 to S. It’s further assumed that 5% of the SO_2 is converted to SO_3, of which 100% is assumed to form H_2SO_4.

Greenhouse gas emission factors are derived using values specified in 40 CFR 98, Subpart C, Tables C-1 and C-2. The global warming potentials used to calculate CO_2e are from Table A-1 in 40 CFR 98, Subpart A, updated in the final rule published April 25, 2024 and effective January 1, 2025. HAP emission factors are referenced from AP-42, Chapter 1.4 Natural Gas Combustion in the absence of unit-specific data.

The permittee shall monitor and maintain records of natural gas usage (in MMscf) on a monthly basis.

The first annual tune-up shall be performed within 13 months of the initial startup of the boiler.

Emission Units 41-44: Existing CI Emergency RICE < 500 HP

Emission Unit	Description	Manufacture Date	Maximum Continuous Rating	Construction Commenced	Fuel Rate
41	Caterpillar, Model 3306 (CT5)	2000	308 HP	2000	15.7 gal/hr
42	Perkins Engine, Model DP150P3 (CT6)	1999	230 HP	1999	11.7 gal/hr
43	Perkins Engine, Model DP150P3 (CT7)	1999	230 HP	1999	11.7 gal/hr
44	Cummins, Model 681A5.9-F-1 (CT Area Fire Pump)	1994	208 HP	1994	10.6 gal/hr

Applicable Regulations:
401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 through 63.6675, Tables 1a through 8, and Appendix A **(Subpart ZZZZ)**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, 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. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30 and is not used to propel a motor vehicle or a vehicle used solely for competition.

Comments:
Greenhouse gas emission factors for these units were referenced from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. In the absence of a better alternative, all other emission factors were derived from values in AP-42 Chapter 3.3 Gasoline and Diesel Industrial Engines.

Four diesel-fired emergency RICE rated at less than 500 HP. These units were manufactured prior to June 12, 2006 and are considered existing emergency RICE subject to the RICE MACT. Emission Units 41-43 are the emergency generators for three of the combustion turbines at Brown Station (Emission Units 27-29), and Emission Unit 44 is a fire pump engine in the Combustion Turbine Area. Emission Unit 44 may occasionally be used for non-emergency purposes – e.g. pump water to clean out oil water separators and to wash the fuel unloading area. Non-emergency use is permitted by 40 CFR 63.6640(f)(3) but is limited to 50 hours per year and counts towards the 100 hours per year provided for maintenance and testing.

These units do not have any specific emission limits, but emissions are minimized by following the maintenance requirements in the RICE MACT. Additionally, a non-resettable hour meter must be installed to ensure the engine meets the requirements for an emergency engine.

Potential emission calculations are based on 500 hours per year, but there are no limits on the use of emergency engines during emergency situations.

Emission Units 45-48: New CI Emergency Fire Pump RICE				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
NO_x + NMHC	10.5 g/kW-hr	40 CFR 60.4205(c), referencing Table 4 to 40 CFR 60, Subpart IIII	NO_x: 604.17 lb/Mgal VOC: 49.32 lb/Mgal (AP-42 3.3-1)	Certified Engine installed and configured according to manufacturer's emission-related specifications (see **Comments** regarding alternate compliance)
CO	3.5 g/kW-hr		130.15 lb/Mgal (AP-42 3.3-1)	
PM	0.54 g/kW-hr		42.47 lb/Mgal (AP-42 3.3-1)	

Initial Construction Date: 2007 (EU 48 rebuilt 2021)

Process Description:
EUs 45 & 46 are steam plant emergency fire pump engines rated at 375 HP, each, with a fuel rate at steady-state and 100% load of 19.2 gallons/hr.
EUs 47 & 48 are FGD emergency quench water / fire pump engines rated at 485 HP, each, with a fuel rate at steady-state and 100% load of 24.8 gallons/hr. The engines are used to provide quench water to cool the flue gas if there is a process upset that could damage the temperature sensitive equipment in the FGD absorber and chimney.

Applicable Regulations:
401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII)**, *Standards of Performance for Stationary Compression Ignition* (CI) *Internal Combustion Engines* (ICE), applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are:

- Manufactured after April 1, 2006, and are not fire pump engines, or
- Manufactured as a certified National Fire Protection Association fire pump engine after July 1, 2006.

Applicable to owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005.

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 through 63.6675, Tables 1a through 8, and Appendix A **(Subpart ZZZZ)**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, 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. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30 and is not used to propel a motor vehicle or a vehicle used solely for competition.

Comments:
Greenhouse gas emission factors for these units were referenced from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. All other emission factors were derived from values in AP-42, Chapter 3.3 Gasoline and

Emission Units 45-48: New CI Emergency Fire Pump RICE

Diesel Industrial Engines.

In response to an NOV issued to KU on 3/24/2022, the Division received an off-permit change on 4/28/2022 to redesignate EUs 47 & 48 as fire pump engines with the corresponding emission limitations from Table 4 of 40 CFR 60, Subpart IIII. Initially, when moving these engines from Insignificant Activities to Section B of the permit, KU requested these not be considered fire pump engines. The engine regulations were new and went through several changes and were confusing, so KU believed this was the correct course of action. However, these engines are driving a centrifugal fire pump to protect equipment: the design of the engine is to pump water. The nameplate states, "this engine may be used only in stationary fire pump applications in accordance with requirements of 40 CFR part 60 and is excluded from the requirements of 40 CFR part 89 and 1039. Installing or using this engine in any other application may be a violation of U.S. federal law subject to civil penalty. This engine may also be used for applications that are not subject to applicable EPA or EU emission regulations, and for export to counties that do not have emission regulations."

Alternate Compliance

To demonstrate compliance with the emission standards in 40 CFR 60 Subpart IIII, the owner or operator is required to purchase a certified engine. However, these engines were purchased without certification from the engine manufacturer and had to conduct performance testing to demonstrate compliance with the applicable emissions limits. EUs 46 and 48 passed testing on 3/31/2010. KU retested EU 48 on 9/20/2021, as the engine had been rebuilt during routine maintenance. The test resulted in NO_x+NMHC exceeding the emission limit listed in the permit, resulting in the redesignation from an emergency generator engine to an emergency fire pump engine, which has a higher NO_x+NMHC emission limit than those required for emergency generator engines.

These units comply with the RICE MACT requirements by complying with the NSPS requirements.

The permittee must maintain records that the engines meet the NSPS emissions standards and install a non-resettable hour meter.

Potential emission calculations are based on 500 hours per year, but there are no limits on the use of emergency engines during emergency situations.

<table>
<tr><th colspan="5">Emission Units 49, 51, 52, 71, & 72: New Emergency CI RICE</th></tr>
<tr><th>Pollutant</th><th>Emission Limit or Standard</th><th>Regulatory Basis for Emission Limit or Standard</th><th>Emission Factor Used and Basis</th><th>Compliance Method</th></tr>
<tr><td>NO_x + NMHC</td><td>EUs 49, 51, & 52:
6.4 g/kW-hr
EUs 71 & 72:
4.0 g/kW-hr</td><td rowspan="3">40 CFR 60.4205(b) referencing 40 CFR 60.4202(a)(2) referencing Appendix I to 40 CFR part 1039</td><td>EUs 49, 51, & 52:
NO_x: 438.4 lb/Mgal
VOC: 12.33 lb/Mgal
(AP-42 3.4-1)
EUs 71 & 72:
NO_x: 119.92 lb/Mgal
VOC: 9.73 lb/Mgal
(40 CFR 60, Subpart IIII)</td><td rowspan="4">Certified Engine installed and configured according to manufacturer's emission-related specifications (see Comments regarding alternate compliance)</td></tr>
<tr><td>CO</td><td>3.5 g/kW-hr</td><td>EUs 49, 51, & 52:
116.45 lb/Mgal
(AP-42 3.4-1)
EUs 71 & 72:
113.44 lb/Mgal
(40 CFR 60, Subpart IIII)</td></tr>
<tr><td rowspan="2">PM</td><td>0.20 g/kW-hr</td><td rowspan="2">EUs 49, 51, & 52:
9.5489 lb/Mgal
(AP-42 3.4-2)
EUs 71 & 72:
6.48 lb/Mgal
(40 CFR 60, Subpart IIII)</td></tr>
<tr><td><u>Smoke Opacity</u>
Acceleration Mode: 20%
Lugging Mode: 15%
Peaks in Acceleration or Lugging Mode: 50%</td><td>40 CFR 60.4205(b) referencing 40 CFR 60.4202(a)(2) referencing 40 CFR 1039.105</td></tr>
<tr><td colspan="5">Initial Construction Date: EU 49: 2010; EUs 51-52: 2014; EUs 71-72: 2024

Process Description:
EU 49: 752 HP (500 kW) Generac SD500 Doosan 390 Tier 2 Certified Emergency Generator Engine with a maximum fuel rating at 100% load of 33.0 gal/hr; Model Year 2010

EUs 51-52: 1,220 HP (each) Cummins QSK23-G7 NR2 Tier 2 Certified Emergency Generator Engine with a maximum fuel rate at 100% load of 51.3 gal/hr; Model Year 2014

EUs 71-72: 229.6 HP (171.2 kW) Cat C7.1 (EPA Family Code: PPKXL07.0PW1) Tier 3 Certified Emergency Generator Engine with a maximum fuel rate at 100% load of 10.0 gal/hr; Model Year 2023; EU 71 is for the Dix Dam Crest Gate & EU 72 is for Dix Dam/Brown Station

Applicable Regulations:
401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 through 60.4219, Tables 1 through 8 (Subpart IIII), Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE), applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are:
Manufactured after April 1, 2006, and are not fire pump engines, or
Manufactured as a certified National Fire Protection Association fire pump engine after July 1, 2006.</td></tr>
</table>

Emission Units 49, 51, 52, 71, & 72: New Emergency CI RICE

Applicable to owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005.

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 through 63.6675, Tables 1a through 8, and Appendix A **(Subpart ZZZZ)**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, 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. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differs from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30 and is not used to propel a motor vehicle or a vehicle used solely for competition.

Comments:

Greenhouse gas emission factors for all units were calculated using values from 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

For Emission Units 49, 51 and 52 all other emission factors were derived from values in AP-42, Chapter 3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines.

For Emission Units 71 and 72 HAP emission factors were referenced from AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines. CO, NO_x, PM and VOC emission factors were derived from limits established in 40 CFR 60, Subpart IIII. The SO_2 emission factor used was derived from values in AP-42, Chapter 3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines, assuming that all sulfur in the diesel fuel being combusted is converted directly to SO_2.

Potential emission calculations are based on 500 hours per year, but there are no limits on the use of emergency engines during emergency situations.

<u>Alternate Compliance</u>

If the engine is not installed, configured, operated, and maintained according to the engine manufacturers' emission-related written instructions or if the emission-related settings are changed in a way that is not permitted by the manufacturer, a maintenance plan and records need to be kept. In addition, the engines need to be tested to ensure compliance with the emission standards. For EUs 49, 51, and 52, subsequent testing is required every 8,760 hours of engine operation or 3 years, whichever comes first.

Emission Units 61 & 62: New Emergency CI RICE (NGCC Project)				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
NO_x + NMHC	**EU 61**: 6.4 **EU 62**: 4.0 (g/kW-hr)	**401 KAR 51:017** and **EU 61:** 40 CFR 60.4205(b) referencing 40 CFR 60.4202(a)(2) referencing Table 2 of Appendix I to 40 CFR part 1039 **EU 62:** 40 CFR 60.4205(c) referencing Table 4 to 40 CFR 60, Subpart IIII	**EU 61**: NO_x: 201.137 lb/Mgal VOC: 5.375 lb/Mgal (40 CFR 1039 Appendix I) **EU 62**: NO_x: 159.678 lb/Mgal VOC: 9.657 lb/Mgal (NSPS Table 4)	Certified Engine installed and configured according to manufacturer's emission-related specifications. See **Comments** for alternate compliance
CO	3.5 g/kW-hr		**EU 61**: 111.35 lb/Mgal (40 CFR 1039 Appendix I) **EU 62**: 112.208 lb/Mgal (NSPS Table 4)	
PM	0.20 g/kW-hr		**EU 61**: 6.363 lb/Mgal (40 CFR 1039 Appendix I) **EU 62**: 6.474 lb/Mgal (NSPS Table 4)	

Initial Construction Date: Proposed June 2026

Process Description:
Fuel: ULSFO (maximum sulfur content of 0.0015 weight percent, or 15 ppm)
EU 61: 2,923 HP (2.18 MW) Kohler KD2000 (or similar) Emergency Generator Engine with a maximum fuel rating at 100% load of 149 gal/hr.
EU 62: 422 HP Clarke JW6H-UFAD80 (or similar) Emergency Generator Engine with a maximum fuel rate at 100% load of 22 gal/hr.

Applicable Regulations:
401 KAR 51:017, *Prevention of significant deterioration of air quality* (CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, and CO_2e), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

Emission Units 61 & 62: New Emergency CI RICE (NGCC Project)

401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII)**, *Standards of Performance for Stationary Compression Ignition* (CI) *Internal Combustion Engines* (ICE), applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are:

- Manufactured after April 1, 2006, and are not fire pump engines, or
- Manufactured as a certified National Fire Protection Association fire pump engine after July 1, 2006.

Applicable to owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005.

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 through 63.6675, Tables 1a through 8, and Appendix A **(Subpart ZZZZ)**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, 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. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differs from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30 and is not used to propel a motor vehicle or a vehicle used solely for competition.

Comments:

Greenhouse gas emission factors for both units were referenced from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. For Emission Unit 61, SO_2 and HAP emission factors were referenced from AP-42, Chapter 3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines with all other emission factors being referenced from 40 CFR 1039, Appendix I. For Emission Unit 62, HAP emission factors were referenced from AP-42, Chapter 3.3 Gasoline And Diesel Industrial Engines with all other emission factors being referenced from NSPS IIII, Table 4.

Potential emission calculations are based on 500 hours per year, but there are no limits on the use of emergency engines during emergency situations.

<u>Alternate Compliance</u>

If the engine is not installed, configured, operated, and maintained according to the engine manufacturers' emission-related written instructions or if the emission-related settings are changed in a way that is not permitted by the manufacturer, a maintenance plan and records need to be kept. In addition, the engines need to be tested to ensure compliance with the emission standards. Subsequent performance testing shall be conducted for EU 61 every 8,760 hours of operation or 3 years, whichever comes first.

Emission Units 7 and 35: Fugitive Emissions				
Pollutant	**Emission Limit or Standard**	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
PM	Discharge of visible fugitive dust emissions beyond the lot line of the property is prohibited	401 KAR 63:010, Section 3(2)	EU 07-1: 0.0004 lb/ton (1996 Application); EU 07-2: 0.0003 lb/ton (1996 Application); EU 07-4: 0.0003 lb/ton (1996 Application); EU 07-5: 0.0003 lb/ton (1996 Application); EU 07-6: 0.0003 lb/ton (1996 Application); EU 35: 1.0389 lb/mile (AP-42 13.2);	N/A

Initial Construction Date: EU 7: 1970; **EU 35**: 1957

Process Description:

Emission Unit	**Description**	**Maximum Operating Rate**	**Control Equipment**
07-1	West Track Hopper	820 tons/hr	Enclosures
07-2	Conveyor A-1		
07-4	Conveyor F		
07-5	Conveyor G		
07-6	Conveyor H		
35	Paved & Unpaved Roadways	33,653 VMT/yr	Dust Suppression (Wet and/or Chemical)

Applicable Regulation:
401 KAR 63:010, *Fugitive emissions*, applicable to an apparatus, operation, or road which emits or may emit fugitive emissions provided that the fugitive emissions from such facility are not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

Comments:
Emission Unit 7 – includes fugitive emission sources associated with transporting coal via conveyors. Coal is received at the west track hopper and transported via conveyors to the coal storage pile, coal crushing operations, or the coal bunkers for Brown Unit 3. The conveyors are partially enclosed. This equipment is not subject to the NSPS for coal handling, Subpart Y, because this equipment commenced construction prior to the classification date of October 27, 1974. This equipment has not been modified or reconstructed.

Emission Unit 35 – includes fugitives emissions generated from traffic on paved and unpaved roadways at Brown Station. Fugitive emissions are controlled by using wet or chemical dust suppression methods.

Emission Units 7 and 35: Fugitive Emissions

Emissions Monitoring

Fugitive dust emissions are monitored by recording actions taken to prevent fugitive emissions for each process (e.g. frequency of water suppression, ensuring enclosures are in good operation condition) on a daily basis and the processing rate for each process on a monthly basis.

Emission Unit 9: Fugitive Coal Handling Operations

Pollutant	Emission Limit or Standard	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	20% opacity	40 CFR 60.254(a)	EU 9-1: 0.0004 lb/ton EU 9-2: 0.0003 lb/ton EU 9-3: 0.0003 lb/ton EU 9-5: 0.0003 lb/ton (1996 Application); EU 9-6: 0.0018 lb/ton (AP-42 & EPA450/3-88-008)	Method 9 reading on a quarterly basis

Reconstruction Date: 1993

Process Description:

Emission Unit	Description	Maximum Operating Rate (tons/hr)	Control Equipment	Control Efficiency
9-1	East Track Hopper	820	Partially Underground	90%
9-2	Conveyor A	820	Enclosures	90%
9-3	Conveyor B	1,640	Enclosures	90%
9-5	Conveyor J	1,640	Enclosures	90%
9-6	Coal Stockpile	1,640	Dust Suppression (Wet and Compaction)	70%

Applicable Regulation:

401 KAR 60:005, Section 2(2)(gg), 40 C.F.R. 60.250 through 60.258 (**Subpart Y**), *Standards of Performance for Coal Preparation and Processing Plants*, applicable to thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and transfer and loading systems that commenced construction, reconstruction, or modification after October 27, 1974 and open storage piles that commenced construction, reconstruction, or modification after May 27, 2009 at coal preparation and processing plants that process more than 200 tons of coal per day.

Comments:

Emission Unit 9 – Fugitive Coal Handling Operations - includes fugitive emission sources associated with transporting coal via conveyors. Coal is received at the east track hopper and transported via conveyors to the coal storage pile, coal crushing operations, or the coal bunkers for Brown Unit 3. The conveyors are partially enclosed. This equipment is subject to the NSPS for coal handling, Subpart Y, because this

Emission Unit 9: Fugitive Coal Handling Operations

equipment commenced reconstruction in 1993, which is after the classification date of October 27, 1974.

Emissions Monitoring
Fugitive dust emissions are monitored by recording control equipment maintenance actions taken to prevent fugitive emissions and the processing rate for each process on a monthly basis. Opacity is determined quarterly according to 40 CFR 60.257 (a)(1) through (3).

Emission Units 13 and 16: Coal Handling Operations

Pollutant	Emission Limit or Standard*	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	For $P \leq 0.5$, $E = 2.58$ For $0.5 < P \leq 30$, $E = 4.10P^{0.67}$ For $P > 30$ $55.0P^{0.11}-40$	401 KAR 61:020, Section 3(2)(a)	EU 13-2: 0.028 lb/tom EU 13-3: 0.028 lb/ton EU 16: 0.02 lb/ton (1996 Application)	Compliance assumed while control equipment is in operation
	20% opacity	401 KAR 61:020, Section 3(1)(a)		Qualitative visual observations on a weekly basis; If emissions observed, a Method 9 & inspection of control

*P is the process rate in tons/hr; E is the emission limit in lb/hr

Initial Construction Date: EUs 13-2 and 13-3: 1970; **EU 16**: 1956

Process Description:

Emission Unit	Description	Maximum Operating Rate (tons/hr)	Control Equipment	Control Efficiency
13-2	Upper Traveling Tripper for Unit 3 (Conveyor K-1)	820	Fabric Filter	99.5%
13-3	Lower Traveling Tripper for Unit 3 (Conveyor K)	820	Fabric Filter	99.5%
16	Coal Crushing: Four Crushers and Crusher House	1,640	Wet Scrubber	99%

Applicable Regulation:
401 KAR 61:020, *Existing process operations*, applicable to all process operations, which are not subject to another emission standard with respect to particulates in 401 KAR Chapter 61, commenced before July 2, 1975.

Comments:
Emission Unit 13 –includes equipment that conveys and drops coal into the coal bunkers for Brown Unit 3. This equipment is located in the same building as Brown Unit 3. This equipment is not subject to the NSPS for coal handling, Subpart Y, because the equipment commenced construction prior to the

Emission Units 13 and 16: Coal Handling Operations

classification date of October 27, 1974. This equipment has not been modified or reconstructed.

Emission Unit 16 –includes four coal crushers and the crusher house. Coal is crushed inside the crusher house prior to being conveyed to the coal bunkers for Brown Unit 3. A wet scrubber controls emissions from the process.

Emissions Monitoring
PM emissions are monitored by recording the processing rate for each piece of equipment, maintaining records of control equipment maintenance and conducting weekly qualitative visual observations of each stack.

Emission Units 30-34: Limestone Handling

Pollutant	Emission Limit or Standard*	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	20% Opacity	401 KAR 59:010, Section 3(1)(a)	**EU 30 – 31:** 0.067 lb/ton **EU 32 – EU 34:** 0.016 lb/SCC (2015 Renewal Application)	For EUs 30 & 31: Qualitative visual observations on a weekly basis with Method 9 readings if emissions observed; For EUs 32-34: Compliance assumed when in compliance with 40 CFR 60, Subpart OOO standards
	For $P \leq 0.50$, $E = 2.34$ For $0.50 < P \leq 30$, $E = 3.59*P^{0.62}$ For $P > 30$ $E = 17.31*P^{0.16}$	401 KAR 59:010, Section 3(2)		Assumed based on application emission factors and emission rates
	0.022 gr/dscf (**EUs 32-34**)	40 CFR 60.672(a) referencing Table 2 of 40 CFR 60, Subpart OOO		Quarterly Method 22 readings with corrective action if emissions observed; or Bag leak detection system
	7% opacity (**EUs 32-34**)			

*P is the process rate in tons/hr; E is the emission limit in lb/hr

Initial Construction Date: EUs 30 and 31: January 2008; **EUs 32-34**: March 2008

Process Description:
Limestone is received, stacked and conveyed to wet crushing and processing operations for the wet FGD.

Emission Units 30-34: Limestone Handling

Emission Unit	Description	Maximum Operating Rating (tons/hr)	Control Equipment	Control Efficiency
30	Limestone truck dump station #1	250	Fabric filter	98%
31	Limestone truck dump station #2	250		
32	Limestone stacking tube	500		
33	Limestone reclaim conveyor #1	500		
34	Limestone reclaim conveyor #2	500		

Applicable Regulation
401 KAR 59:010, *New process operations*, applicable to all process operations, which are not subject to another emission standard with respect to particulates in 401 KAR Chapter 59, commenced on or after July 2, 1975.

401 KAR 60:005, Section 2(2)(qqq), 40 C.F.R. 60.670 through 60.676, Tables 1 through 3 (**Subpart OOO**), *Standards of Performance for Nonmetallic Mineral Processing Plants*, except as provided in 40 CFR 60.670(a)(2), (b), (c), and (d), applicable to each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station in fixed or portable nonmetallic mineral processing plants. Also applicable to crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin. The truck dump stations (**EUs 30 & 31**) are exempt from the particulate matter standards in 40 CFR 60.672; however, they must still meet the other applicable requirements of 40 CFR 60, Subpart OOO for nonmetallic mineral processing plants.

Comments:
Initial performance testing required by 40 CFR 60, Subpart OOO was completed in January 2011.

Emissions Monitoring
As of issuance of V-26-036, PM emissions are monitored using quarterly Method 22 observations, rather than using a bag leak detection system, and recording the monthly processing rate for each unit.

Emission Unit 50: CCR Landfill Operations and Haul Trucks

Pollutant	Emission Limit or Standard	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	Discharge of visible fugitive dust emissions beyond the lot line of the property is prohibited for more than 5 min. during any 60 min. and more than 20 min. during any 24 hr.	401 KAR 63:010, Section 3(2)	See table below	N/A

Initial Construction Date: June 2013

Process Description:
Coal combustion residual disposal system: Landfill and material transport operations. Controls include

Emission Unit 50: CCR Landfill Operations and Haul Trucks

wet suppression by water, cleaning, and road maintenance.

Emission Unit	Description	Maximum Throughput (mile/hr)	PM Emission Factor (lb/mile)	Emission Factor Basis
50-1	Unpaved Empty Bottom Ash Transport	0.0163	3.9223	AP-42 13.2.2
50-3	Unpaved Empty Gypsum-Like Transport	0.1268	3.9223	
50-4	Unpaved Full Bottom Ash Transport	0.0163	4.2841	
50-6	Unpaved Ful Gypsum-Like Transport	0.1268	4.2841	
50-7	Paved/Unpaved Empty Bottom Ash Transport	0.0482	3.3624	AP-42 13.2.1 and 13.2.2
50-8	Paved/Unpaved Full Bottom Ash Transport	0.0482	5.3629	
50-9	Paved/Unpaved Empty Fly Ash Transport	0.2112	3.1022	
50-10	Paved/Unpaved Full Fly Ash Transport	0.2112	4.9878	
50-11	Paved/Unpaved Empty Gypsum-Like Transport	0.3579	3.5119	
50-12	Paved/Unpaved Full Gypsum-Like Transport	0.3579	5.5786	
50-13	Travel Heavy Equipment Landfill	0.042	4.2841	AP-42 13.2.2

Applicable Regulation

401 KAR 63:010, *Fugitive emissions*, applicable to an apparatus, operation, or road which emits or may emit fugitive emissions provided that the fugitive emissions from such facility are not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

Comments:

Emissions Monitoring

Fugitive dust emissions are monitored by recording actions taken to prevent fugitive emissions for each process (e.g. frequency of water suppression, ensuring enclosures are in good operation condition) on a daily basis and the processing rate for each process on a monthly basis.

Emission Unit 38: Cooling Tower

Pollutant	Emission Limit or Standard*	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	For $P \leq 0.5$, $E = 2.58$; For $0.5 < P \leq 30$, $E = 4.10P^{0.67}$; For $P > 30$ $E = 55.0P^{0.11}-40$	401 KAR 61:020, Section 3(2)(a)	0.067 lb/MMgal (AP-42 Table 13.4)	Compliance assumed while drift eliminators are in operation
	40% opacity	401 KAR 61:020, Section 3(1)(a)		

*P is the process rate in tons/hr; E is the emission limit in lb/hr

Initial Construction Date: 1971

Process Description:
Forced Draft cooling tower
Maximum Circulating Water Rate: 10.37 MMgal/hr
Control: Drift Eliminators

Applicable Regulation
401 KAR 61:020, *Existing process operations*, applicable to all process operations, which are not subject to another emission standard with respect to particulates in 401 KAR Chapter 61, commenced before July 2, 1975.

Precluded Regulation:
401 KAR 63:002, Section 2(4)(j), 40 C.F.R. 63.400 through 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling*, precluded by prohibiting the use of chromium-based water treatment chemicals.

Comments:
The cooling tower is equipped with drift eliminators which reduce emissions.

Emission Unit 63: 10-Cell Mechanical Draft Plant Cooling Tower				
Pollutant	**Emission Limit or Standard***	**Regulatory Basis for Emission Limit or Standard**	**Emission Factor Used and Basis**	**Compliance Method**
PM	20% Opacity	401 KAR 59:010, Section 3(1)(a)	0.0826 lb/MMgal (AP-42 Table 13.4)	Assumed to be in compliance when the cooling towers are operated and maintained in accordance with the manufacturer's specifications and recommendations
	For $P \leq 0.50$, $E = 2.34$ For $0.50 < P \leq 30$, $E = 3.59*P^{0.62}$ For $P > 30$ $E = 17.31*P^{0.16}$	401 KAR 59:010, Section 3(2)		

*P is the process rate in tons/hr; E is the emission limit in lb/hr

Initial Construction Date: Proposed June 2026

Process Description:
10-cell mechanical draft back-to-back counter-flow wet cooling tower provides cooling water via indirect heat transfer for condensing steam exiting the steam turbine.
Maximum Circulating Water Rate: 95,000 gpm
Maximum Total Dissolved Solids (TDS): 990 ppm
Controls: Inherent Drift Eliminators

Applicable Regulation:
401 KAR 51:017, *Prevention of significant deterioration of air quality* (PM, PM_{10}, & $PM_{2.5}$), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

401 KAR 59:010, *New process operations*, 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 C.F.R. 63.400 through 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling*, precluded by prohibiting the use of chromium-based water treatment chemicals.

Comments:
<u>BACT</u>
Drift eliminators certified by the manufacturer to have 0.001% or less drift loss.

PM emissions are generated from the particulates encapsulated in the water droplets. PTE calculations are

Emission Unit 63: 10-Cell Mechanical Draft Plant Cooling Tower

based on 95,000 gallons of recirculating water per minute, assuming a density of 8.34 lb/gal with TDS of 990 ppm and a drift percentage of 0.0010%. For PM_{10} and $PM_{2.5}$, conversions are made using interpolated fractions from a table of drift droplet size distribution testing from EPRI test facility published in "Calculating Realistic PM_{10} Emission Factors from Cooling Towers" by Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

Emission Unit 64: Circuit Breakers

Pollutant	Emission Limit or Standard*	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
SF_6	Leakage not to exceed 0.5% by weight	401 KAR 51:017	1.8 lb/yr; see comments	Monitor leak detection alarms; maintain records of any detected leaks and corrective action taken

Initial Construction Date: Proposed June 2026

Process Description:
Two NGCC Circuit breakers for the NGCC with SF_6 circuits
Maximum Capacity: one at 30 pounds and one at 330 pounds SF_6

Applicable Regulation:
401 KAR 51:017, *Prevention of significant deterioration of air quality* (CO_2e), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

Comments:
BACT
Install and operate a leak detection system for SF_6.

The PTE for CO_2e is based on a maximum leak of 0.5% of the total SF_6 per year, or 0.005 x 360 lb SF_6 = 1.8 lb/yr. The GWP is 23,500 according to Table A-1 in 40 CFR 98, Subpart A, updated in the final rule published on April 25, 2024 and effective January 1, 2025. Potential CO_2e emissions are 21.15 tpy.

Emission Units 65: Lube Oil System
Initial Construction Date: Proposed June 2026 **Process Description:** The gas and steam turbines have an internal lube oil storage and distribution system. Due to the high operating temperatures, small amounts of lube oil may vaporize. The gas turbine demister system minimizes lube oil loss to the atmosphere. Maximum Operating Rate: 0.5 gallons/day Lube Oil Density: 7.28 lb/gal Control Device: Demister System **Applicable Regulation:** **401 KAR 51:017**, *Prevention of significant deterioration of air quality* (VOC), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source. **Comments:** <u>BACT</u> Install, operate, and maintain records of the demisters for the lubricating oil system. The lube oil module is sized for an operating volume of 9,250 gallons and 2,000 gallons of flow back from the equipment and piping when the CT (EU 58) is shut down. No additional tanks are required for the lube oil storage. The maximum rate of lube oil loss is set at 0.5 gallons per day. For PTE calculations, 100% VOC content is assumed, so the maximum amount lost is 0.5 gal/day x 7.28 lb/gal x 365 day/yr / 2,000 lb/ton = 0.66 tpy.

Emission Units 66 & 67: Storage Tanks

Initial Construction Date: Proposed June 2026

Process Description:
EU 66: 3,733-gallon tank for the emergency generator engine (EU 61) to store ultra low sulfur fuel oil (ULSFO)
EU 67: 300-gallon tank for the emergency fire pump engine (EU 62) to store ULSFO

Applicable Regulation:
401 KAR 51:017, *Prevention of significant deterioration of air quality* (VOC), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

State-Origin Requirement:
401 KAR 63:020, *Potentially hazardous matter or toxic substances*

Comments:
<u>BACT</u>
Install and operate a submerged fill pipe and overfill/spill protection. (Maintain records of installation.)

VOC emissions from EUs 66 and 67 are generated through the normal operation of the fuel tanks. Breathing losses occur as the fuel is stored in the tank over time and working losses occur as fuel is being filled and/or dispensed – both of which produce 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. PTE calculations utilize TankESP software using methodology presented in AP-42, Section 7.1. The usage assumes each emergency engine needs fuel to operate 500 hours per year.

These thanks are not subject to 401 KAR 59:050, New storage vessels for petroleum liquids, because "Petroleum liquids" does not mean Number 2 through Number 6 fuel oils, nor are they 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 these tanks are less than 20,000 gallons.

Emission Units 68: NGCC Paved Haul Roads

Pollutant	Emission Limit or Standard	Regulatory Basis for Emission Limit or Standard	Emission Factor Used and Basis	Compliance Method
PM	Discharge of visible fugitive dust emissions beyond the lot line of the property is prohibited for more than 5 min. during any 60 min. and more than 20 min. during any 24 hr.	401 KAR 63:010, Section 3(2)	AP-42, Table 13.2.1 (See table below)	N/A

Initial Construction Date: Proposed June 2026

Process Description:
Paved roads used to transport various chemicals, including aqueous anhydrous ammonia, cooling tower chemicals, and water treatment chemicals, throughout Brown Station

Emission Unit	Description	Maximum Throughput (VMT/yr)	Weight (tons)	PM Emission Factor (lb/VMT)
68-1	Paved Aqueous Anhydrous Ammonia Transport	465	23	PM: 0.727 PM_{10}: 0.142 $PM_{2.5}$: 0.021
68-2	Paved Cooling Tower Chemical Transport	171	24	PM: 0.761 PM_{10}: 0.148 $PM_{2.5}$: 0.022
68-3	Paved Water Treatment Chemical Transport	23	11	PM: 0.24 PM_{10}: 0.047 $PM_{2.5}$: 0.007

Applicable Regulation:
401 KAR 63:010, *Fugitive emissions*, applicable to an apparatus, operation, or road which emits or may emit fugitive emissions provided that the fugitive emissions from such facility are not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

401 KAR 51:017, *Prevention of significant deterioration of air quality* (PM, PM_{10}, & $PM_{2.5}$), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

Comments:
BACT
Dust control plan: Paved road, speed limit signs, watering, dust suppression, and good housekeeping.

PTE calculations utilize the average vehicle weight, a particle size multiplier found in AP-42, Section 13.2.1 and a silt loading of 0.6 g/m^2. For conservation, no control efficiency for fugitive dust suppression

Emission Units 68: NGCC Paved Haul Roads

control methods will be utilized. However, the calculations include a reduction to account for 125 days of precipitation per year and a reduction factor for exhaust, brake wear, and tire wear from the vehicle.

Emissions Monitoring
Fugitive dust emissions are monitored by recording actions taken to prevent fugitive emissions for each process (e.g. frequency of water suppression, ensuring enclosures are in good operation condition) on a daily basis and the processing rate for each process on a monthly basis.

Emission Unit 69: Natural Gas Piping Fugitives

Initial Construction Date: Proposed June 2026

Process Description:
Components to connect a natural gas pipeline to provide the requisite fuel to all of the natural gas-fired units installed as part of the NGCC project.

Piping Component	Component Count
Gas/Vapor Valves	304
Relief Valves	25
Flanges	496
Vents	69
Compressor Components	3
Sampling Connections	3

NOTE - The pipeline equipment count listed above reflects an estimated count of the equipment as of the date of issuance of this permit V-26-036 but is not intended to limit the permittee to the exact numbers specified. The permittee may add or remove pipeline equipment 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 emissions on potential to emit.

Applicable Regulation
401 KAR 51:017, *Prevention of significant deterioration of air quality* (VOC and CO_2e), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

Comments:
BACT
Audio/visual/olfactory leak detection program to detect natural gas leaks at least once per day. Repair each identified source of fugitive emissions as soon as practicable, but no later than 30 calendar days after detection. Maintain records of leaks and corrective actions taken.

Potential emissions are calculated using component-specific emission factors from Table 2-4 in EPA-453/R-95-017 *Protocol for Equipment Leak Emission Estimates* in conjunction with site specific natural gas VOC content weight percentages.

Emission Unit 70: Sulfuric Acid Storage Tank

Initial Construction Date: Proposed June 2026

Process Description:
12,200-gallon storage tank for 93% by weight aqueous sulfuric acid.

Applicable Regulation
401 KAR 51:017, *Prevention of significant deterioration of air quality* (H_2SO_4), applicable to the construction of 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). Section 8 to 16 applies to a major modification of an existing major stationary source.

Comments:
<u>BACT</u>
Follow manufacturer's recommended procedures for filling, storing, and emptying the tank.

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 sulfuric acid in gallons per year.

Insignificant Activities

	Description	Generally Applicable Regulation
1.	Station fuel-oil tanks (2 @ 1,100,000 gallons each)	None
2.	#2 Fuel Oil tank Storage & Light-off for Unit 3 None (525,000 gallons) installed 1973	
3.	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	None
4.	Unleaded gasoline storage tanks	None
5.	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	None
6.	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	None
7.	Burning Off-Specification Used Oil for Energy Recovery	401 KAR 61:020
8.	Kerosene Tank (500 gallons)	None
9.	Distillate Oil and/or Propane Coal Belt Heaters	None
10.	Limestone Storage Pile	401 KAR 63:010
11.	Limestone Reclaim Maintenance Tunnel Exhaust Vent	401 KAR 59:010
12.	Sorbent Storage Silos (for SO_3 mitigation)	401 KAR 59:010
13.	Natural Gas Distillate tank (2,000 gallons)	None
14.	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	None
15.	Diesel Fuel tank for emergency fire pump (300 gallons)	None
16.	Liquid Hg Control Additives	None
17.	Diesel Fuel tank for emergency generator (837 gallons)	None
18.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons)	None
19.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons)	None
20.	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	None
21.	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	None
22.	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	None
23.	Lab Fume Hood	None
24.	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons)	None
25.	PAC Storage Silos	401 KAR 59:010
26.	Bottom Ash Transport	401 KAR 63:010
27.	Fly Ash Transport	401 KAR 63:010
28.	Gypsum Transport & Process Water System Solids	401 KAR 63:010
29.	Landfill Truck Loading and Unloading & Process Water System Solids	401 KAR 63:010
30.	Active Area of the CCR Landfill (Wind Erosion) & Process Water System Solids	401 KAR 63:010
31.	Slipstream Carbon Dioxide (CO_2) capture System – Research	401 KAR 63:010
32.	Bottom Ash Handling including storage pile (associated with CCR landfill operations)	401 KAR 63:010
33.	Fly Ash Handling including load out to trucks (associated with CCR landfill operations)	401 KAR 63:010

Insignificant Activities	
34. Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)	401 KAR 63:010
35. Fly Ash Storage Silos (2) (associated with CCR landfill operations)	401 KAR 63:010 401 KAR 59:010
36. Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)	401 KAR 63:010
37. NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)	None
38. Diesel Fuel Tanks for emergency generators (2 @ 900 gallons)	None
39. Diesel Fuel Tanks (500, 2000, 3@ 550, 1,100 gallons) T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	None
40. Mobile Diesel Fuel Tank (251 gallons/square tank) T-39 (Stored in CT Warehouse when not in use)	None
41. Unit 3 Propylene Glycol Tank (3,000 gal)	None
42. Hydroelectric Building Lube Oil Tanks (T-31 and T-32)	None
43. CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)	None
44. Unit 3 Hydrazine Monohydrate Tote (189 gal)	None
45. Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)	401 KAR 59:010
46. Anhydrous Ammonia Tank (BR CT Ice Plant)	401 KAR 63:020
47. Anhydrous Ammonia Tanks (BR3 SCR)	401 KAR 63:020
48. Aqueous Ammonia (19%) Tank (BR12)	401 KAR 63:020
49. Existing Natural Gas Piping Fugitives	401 KAR 63:020

Testing Requirements\Results

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 3	PJFF	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0042 lb/MMBtu	417.6-464 MW	CMN20260004	3/17/26
EU 3	DSI/SCR	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-13	473.1 tpy	0.005 lb/MMBtu	417.6-464 MW	CMN20260001	3/18/26
EU 24 (Unit 10)	Water Injection	NO_x @ 100 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	26.7 ppm @ 15% O_2	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	Water Injection	NO_x @ 84 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	29.8 ppm @ 15% O_2	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	Water Injection	NO_x @ 67 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	28.3 ppm @ 15% O_2	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	25.7 ppm @ 15% O_2	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	----	CO @ 100 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	2.3 lb/hr	N/A	CMN20250006	9/18/25

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 24 (Unit 10)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	16.1 lb/hr	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	----	VOC @ 100 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	3.4 lb/hr	N/A	CMN20250006	9/18/25
EU 24 (Unit 10)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	5.8 lb/hr	N/A	CMN20250006	9/18/25
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0025 lb/MMBtu	Emission Factor	CMN20250004	3/6/25
EU 3	----	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0044 lb/MMBtu	N/A	CMN20250003	4/30/25
EU 3	----	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0041 lb/MMBtu	N/A	CMN20240002	3/19/24
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0025 lb/MMBtu	N/A	CMN20240001	3/19/24

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 23 (Unit 9)	Low NO_x Burners	NO_x @ 120 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	30.53 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	Low NO_x Burners	NO_x @ 96 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.99 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	Low NO_x Burners	NO_x @ 73 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.82 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	Low NO_x Burners	NO_x @ 50 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.47 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	----	CO @ 120 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.76 lb/hr	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	43.73 lb/hr	N/A	CMN20230007	11/28/23
EU 23 (Unit 9)	----	VOC @ 120 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.58 lb/hr	N/A	CMN20230007	11/28/23

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 23 (Unit 9)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	3.29 lb/hr	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	Low NO_x Burners	NO_x @ 127 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	31.46 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	Low NO_x Burners	NO_x @ 96 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	30.72 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	Low NO_x Burners	NO_x @ 73 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	31.64 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	Low NO_x Burners	NO_x @ 50 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.49 ppm @ 15% O_2	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	----	CO @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.86 lb/hr	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	4.05 lb/hr	N/A	CMN20230007	11/28/23

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 26 (Unit 11)	----	VOC @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	4.51 lb/hr	N/A	CMN20230007	11/28/23
EU 26 (Unit 11)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.64 lb/hr	N/A	CMN20230007	11/28/23
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0024 lb/MMBtu	Emission Factor	CMN20230004	8/29/23
EU 3	PJFF	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.01 lb/MMBtu	N/A	CMN20230002	8/29/23
EU 3	PJFF	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.00456 lb/MMBtu	N/A	CMN20220006	6/28-30/22
EU 25 (Unit 8)	Low NO_x Burners	NO_x @ 103 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	36 ppm @ 15% O_2	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	Low NO_x Burners	NO_x @ 87 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	35.95 ppm @ 15% O_2	N/A	CMN20220004	5/17/22

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 25 (Unit 8)	Low NO_x Burners	NO_x @ 68 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	36.40 ppm @ 15% O_2	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	Low NO_x Burners	NO_x @ 50 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	36.28 ppm @ 15% O_2	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	----	CO @ 103 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	1.0 lb/hr	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	5.27 lb/hr	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	----	VOC @ 103 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.63 lb/hr	N/A	CMN20220004	5/17/22
EU 25 (Unit 8)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.79 lb/hr	N/A	CMN20220004	5/17/22
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0073 lb/MMBtu	Emission Factor	CMN20220003	8/9/22

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 48	----	NO_x + THC	40 CFR 60, Subpart IIII	See Section B Notes for EU 48	U.S. EPA Reference Method 7E/25A	2.98 g/HP-hr	5.34 g/HP-hr	N/A	CMN20210008	9/20/21
EU 48	----	CO	40 CFR 60, Subpart IIII	See Section B Notes for EU 48	U.S. EPA Reference Method 10	2.61 g/HP-hr	0.52 g/HP-hr	N/A	CMN20210008	9/20/21
EU 48	----	PM	40 CFR 60, Subpart IIII	See Section B Notes for EU 48	U.S. EPA Reference Method 5	0.15 g/HP-hr	0.006 g/HP-hr	N/A	CMN20210008	9/20/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 171 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	11.59 ppm @ 15% O_2	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 149 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	16.55 ppm @ 15% O_2	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 127 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	16.16 ppm @ 15% O_2	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 105 MW combusting natural gas	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	15.52 ppm @ 15% O_2	N/A	CMN20210006	1/11/22

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 28 (Unit 7)	----	CO @ 171 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	4.23 lb/hr	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	----	CO @ 149 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	10.15 lb/hr	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	----	CO @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	14.68 lb/hr	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	57.26 lb/hr	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	----	VOC @ 171 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	3.07 lb/hr	N/A	CMN20210006	1/11/22
EU 28 (Unit 7)	----	VOC @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	6.31 lb/hr	N/A	CMN20210006	1/11/22
EU 29 (Unit 5)	Water Injection	NO_x @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	18.13 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 29 (Unit 5)	Water Injection	NO_x @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	20.27 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	Water Injection	NO_x @ 75 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.47 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	23.75 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	3.22 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	7.03 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 75 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	6.80 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	24.25 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 29 (Unit 5)	----	VOC @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.99 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.12 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	21.43 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 138 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.79 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 122 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	21.14 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.00 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	1.7 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 28 (Unit 7)	----	CO @ 138 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	2.81 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 122 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	9.72 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	46.30 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	VOC @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	1.38 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	VOC @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	4.78 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	39.73 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 88 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.62 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 25 (Unit 8)	Water Injection	NO_x @ 69 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	39.48 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	40.25 ppm @ 15% O_2	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.97 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 88 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	2.09 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 69 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	1.45 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	10.34 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	VOC @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.08 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 25 (Unit 8)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.22 lb/hr	N/A	CMN20210005	3/2-3/21; 3/16-18/21
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0016 lb/MMBtu	Emission Factor	CMN20210004	4/19/21
EU 3	PJFF	PM	Consent Degree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.006 lb/MMBtu	N/A	CMN20210003	4/20/21 & 4/27/21
EU 29 (Unit 5)	Water Injection	NO_x @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	18.3 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	Water Injection	NO_x @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	20.27 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	Water Injection	NO_x @ 75 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.47 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	23.75 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 29 (Unit 5)	----	CO @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	3.22 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	7.03 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 75 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	6.80 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	24.25 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	VOC @ 121 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.99 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 29 (Unit 5)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.12 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	21.43 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 138 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.79 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 122 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	21.14 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	Low NO_x Burners	NO_x @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	22.00 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	1.70 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 138 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	2.81 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 122 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	9.72 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	46.3 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 28 (Unit 7)	----	VOC @ 153 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	1.38 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 28 (Unit 7)	----	VOC @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	4.78 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	39.73 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 88 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	32.62 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 69 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	39.48 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	40.25 ppm @ 15% O_2	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.97 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 25 (Unit 8)	----	CO @ 88 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	2.09 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 69 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	1.45 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	10.34 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	VOC @ 108 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.08 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 25 (Unit 8)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	2.22 lb/hr	N/A	CMN20210001	3/2-3/21; 3/16-18/21
EU 24 (Unit 10)	Water Injection	NO_x @ 104 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	28.31 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 84 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	26.84 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 24 (Unit 10)	Water Injection	NO_x @ 67 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	27.81 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	28.98 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	CO @ 104 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.93 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	7.24 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	VOC @ 104 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.23 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.93 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	Be content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	3.37E-3 lb/hr	< 0.001 µg/L [A]	N/A	CMN20200007	7/7-8/20

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 24 (Unit 10)	----	Sulfur content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	0.26% when EU 23-29 simultaneously operation; 0.30% all other operation scenarios	0.038 gr/100 scf	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 98 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	47.82 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 84 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	45.7 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 67 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	41.74 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	Water Injection	NO_x @ 50 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	31.94 ppm @ 15% O_2	N/A	CMN20200007	7/7-8/20

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 24 (Unit 10)	----	CO @ 98 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	1.49 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	CO @ 50 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	0.32 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	VOC @ 98 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.89 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	VOC @ 50 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	0.71 lb/hr	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	Be content of fuel oil	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	3.37E-3 lb/hr	< 0.001 µg/L [A]	N/A	CMN20200007	7/7-8/20
EU 24 (Unit 10)	----	Sulfur content of fuel oil	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	0.26% when EU 23-29 simultaneously operation; 0.30% all other operation scenarios	0.03 gr/100 scf	N/A	CMN20200007	7/7-8/20

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 24 (Unit 10)	----	PM combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 5	67 lb/hr	13.85 lb/hr	N/A	CMN20200007	7/7-8/20
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0031 lb/MMBtu	Emission Factor	CMN20200005	10/20/20
EU 27 (Unit 6)	Low NO_x Burners	NO_x @ 143 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	11.17 ppm @ 15% O_2	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	Low NO_x Burners	NO_x @ 130 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	7.69 ppm @ 15% O_2	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	Low NO_x Burners	NO_x @ 118 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	7.66 ppm @ 15% O_2	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	Low NO_x Burners	NO_x @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	8.79 ppm @ 15% O_2	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	----	CO @ 143 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	12.11 lb/hr	N/A	CMN20190009	7/2/19

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 27 (Unit 6)	----	CO @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	112.5 lb/hr	110.47 lb/hr	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	----	VOC @ 143 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	1.37 lb/hr	N/A	CMN20190009	7/2/19
EU 27 (Unit 6)	----	VOC @ 105 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	30.6 lb/hr	5.33 lb/hr	N/A	CMN20190009	7/2/19
EU 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0118 lb/MMBtu	Emission Factor	CMN20190007	9/25/19
EU 3	PJFF	PM	Consent Degree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0178 lb/MMBtu	N/A	CMN20190005	9/25/19
EU 26 (Unit 11)	Water Injection	NO_x @ 105 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	36.06 ppm @ 15% O_2	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	Water Injection	NO_x @ 87 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	28.99 ppm @ 15% O_2	N/A	CMN20190001	2/6/19

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 26 (Unit 11)	Water Injection	NO_x @ 69 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	30.11 ppm @ 15% O_2	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	Water Injection	NO_x @ 50 MW combusting fuel oil	401 KAR 51:017 and 40 CFR 60.332(a)	Every 20 calendar quarters	U.S. EPA Reference Method 7E	65 ppm @ 15% O_2	29.27 ppm @ 15% O_2	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	CO @ 105 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	2.41 lb/hr	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	CO @ 50 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	1.11 lb/hr	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	VOC @ 105 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	3.31 lb/hr	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	VOC @ 50 MW combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.76 lb/hr	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	Be content of fuel oil	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	3.37E-3 lb/hr	< 0.062 µg/L [A]	N/A	CMN20190001	2/6/19

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 26 (Unit 11)	----	Sulfur content of fuel oil	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	0.26% when EU 23-29 simultaneously operation; 0.30% all other operation scenarios	< 0.050% [A]	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	----	PM combusting fuel oil	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 5	67 lb/hr	25.43 lb/hr	N/A	CMN20190001	2/6/19
EU 26 (Unit 11)	Water Injection	NO_x @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	33.8 ppm @ 15% O_2	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	Water Injection	NO_x @ 102 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	33.3 ppm @ 15% O_2	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	Water Injection	NO_x @ 76 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	34.59 ppm @ 15% O_2	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	42 ppm @ 15% O_2	37.87 ppm @ 15% O_2	N/A	CMN20180010	12/6-7/18

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 26 (Unit 11)	----	CO @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	4.86 lb/hr	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	----	CO @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 10	75 lb/hr	14.17 lb/hr	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	----	VOC @ 127 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	4.51 lb/hr	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	----	VOC @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 25A	20.4 lb/hr	1.96 lb/hr	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	----	Be content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	3.37E-3 lb/hr	< 0.0024 µg/L [A]	N/A	CMN20180010	12/6-7/18
EU 26 (Unit 11)	----	Sulfur content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	0.26% when EU 23-29 simultaneously operation; 0.30% all other operation scenarios	0.07328 gr/100 scf	N/A	CMN20180010	12/6-7/18

Emission Point	Control Device	Parameter	Regulatory Basis	Frequency	Test Method	Permit Limit	Test Result	Operating Parameter(s) Established During Test	Activity Graybar	Date of last Compliance Testing
EU 1, 2, & 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0145 lb/MMBtu	Emission Factor	CMN20180007	5/24/18
EU 3	PJFF	PM	Consent Degree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0083 lb/MMBtu	N/A	CMN20180006	9/6/18
EU 29 (Unit 5)	Water Injection	NO_x @ 125 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	17.46 ppm @ 15% O_2	N/A	CMN20170010	12/19/17
EU 29 (Unit 5)	Water Injection	NO_x @ 100 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	19.35 ppm @ 15% O_2	N/A	CMN20170010	12/19/17
EU 29 (Unit 5)	Water Injection	NO_x @ 75 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	21.18 ppm @ 15% O_2	N/A	CMN20170010	12/19/17
EU 29 (Unit 5)	Water Injection	NO_x @ 50 MW combusting natural gas	401 KAR 51:017	Every 20 calendar quarters	U.S. EPA Reference Method 7E	25 ppm @ 15% O_2	19.91 ppm @ 15% O_2	N/A	CMN20170010	12/19/17
EU 29 (Unit 5)	----	Be content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	3.37E-3 lb/hr	< 0.0027 µg/L [A]	N/A	CMN20170010	12/19/17

Emission Point	**Control Device**	**Parameter**	**Regulatory Basis**	**Frequency**	**Test Method**	**Permit Limit**	**Test Result**	**Operating Parameter(s) Established During Test**	**Activity Graybar**	**Date of last Compliance Testing**
EU 29 (Unit 5)	----	Sulfur content of natural gas	401 KAR 51:017	Every 20 calendar quarters	Fuel Analysis	0.26% when EU 23-29 simultaneously operation; 0.30% all other operation scenarios	0.07423 gr/100 scf	N/A	CMN20170010	12/19/17
EU 3	PJFF	PM	Consent Decree	Annual	U.S. EPA Reference Method 5B	0.03 lb/MMBtu	0.0017 lb/MMBtu	N/A	CMN20170008	6/6/17
EU 1, 2, & 3	WFGD	SAM	401 KAR 50:055	Annual	U.S. EPA CTM-013	473.1 tons/yr	0.0167 lb/MMBtu	Emission Factor	CMN20170005	7/25/17

Footnotes:
[A] Detection limit reported.

SECTION 4 – SOURCE INFORMATION AND REQUIREMENTS

Table A - Group Requirements:

N/A

Table B - Summary of Applicable Regulations:

Applicable Regulations	Emission Unit
401 KAR 51:017, *Prevention of significant deterioration of air quality*	EUs 23-29, 58-70
401 KAR 51:160, *NO_x requirements for large utility and industrial boilers*	EU 3
401 KAR 51:210, *CAIR NO_x annual trading program*	EU 3
401 KAR 51:220, *CAIR NO_x ozone season trading program*	EU 3
401 KAR 51:230, *CAIR SO_2 trading program*	EU 3
401 KAR 51:240, codifying **40 C.F.R. 97.401 through 97.435, Subpart AAAAA**, *Cross-State Air Pollution Rule (CSAPR) NO_x annual trading program*	EUs 3, 23-29 & 58
401 KAR 51:250, codifying **40 C.F.R. 97.801 through 97.835, Subpart EEEEE**, *Cross-State Air Pollution Rule (CSAPR) NO_x ozone season group 2 trading program*	EUs 3, 23-29 & 58
401 KAR 51:260, codifying **40 C.F.R. 97.601 through 97.635, Subpart CCCCC**, *Cross-State Air Pollution Rule (CSAPR) SO_2 group 1 trading program*	EUs 3, 23-29 & 58
401 KAR 52:060, *Acid rain permits*	EUs 3, 23-29 & 58
401 KAR 59:010, *New process operations*	EUs 30-34, 63
401 KAR 59:015, *New indirect heat exchangers*	EU 58 (HRSG), 55-57, 59 & 60
401 KAR 61:015, *Existing indirect heat exchangers*	EU 3
401 KAR 61:020, *Existing process operations*	EUs 13, 16 & 38
401 KAR 63:010, *Fugitive emissions*	EUs 7, 35, 50 & 68

Applicable Regulations	**Emission Unit**
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*	EUs 59 & 60
401 KAR 60:005, Section 2(2)(gg), 40 C.F.R. 60.250 through 60.258 (**Subpart Y**), *Standards of Performance for Coal Preparation and Processing Plants*	EU 9
401 KAR 60:005, Section 2(2)(pp), 40 C.F.R. 60.330 through 60.335 **(Subpart GG**) *Standards of Performance for Stationary Gas Turbines*	EUs 23-29
401 KAR 60:005, Section 2(2)(qqq), 40 C.F.R. 60.670 through 60.676, Tables 1 through 3 (**Subpart OOO**), *Standards of Performance for Nonmetallic Mineral Processing Plants*	EUs 30-34
401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 through 60.4219, Tables 1 through 8 (**Subpart IIII)**, *Standards of Performance for Stationary Compression Ignition* (CI) *Internal Combustion Engines* (ICE)	EUs 45-49, 51, 52, 61, 62, 71, & 72
40 CFR 60, Subpart KKKKa, *Standards of Performance for Stationary Combustion Turbines*	EU 58
401 KAR 60:005, Section 2(2)(jjjj), 40 C.F.R. 60.5508 to 60.5580, Tables 1 to 3 (**Subpart TTTTa**), *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*	EU 58
401 KAR 63:002, Section 2(4)(dddd), 40 C.F.R. 63.6080 to 63.6175, Tables 1 to 7 (**Subpart YYYY**), *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*	EU 23-29 & 58
401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 through 63.6675, Tables 1a through 8, and Appendix A **(Subpart ZZZZ)**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*	EU 41-44, 45-48, 49, 51, 52, 61, 62, 71, &72
401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 63.7480 to 63.7575, Tables 1 to 13 (**Subpart DDDDD**), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*	EUs 55-57, 59, & 60
401 KAR 63:002, Section 2(4)(yyyy), 40 C.F.R. 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*	EU 3
40 CFR part 64, *Compliance Assurance Monitoring*	EUs 3 & 58
40 CFR 75, Appendix E, *Optional* NO_x *Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*	EUs 23-29

SECTION 4 – SOURCE INFORMATION AND REQUIREMENTS (CONTINUED)

Table C - Summary of Precluded Regulations:

Precluded Regulations	Emission Unit
401 KAR 63:002, Section 2(4)(j), 40 C.F.R. 63.400 through 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling*	EU 63

Table D - Summary of Non-Applicable Regulations:

Non-Applicable Regulations	Emission Unit
401 KAR 60:005, Section 2(2)(b), 40 C.F.R. 60.40Da through 60.52Da (**Subpart Da**), *Standards of Performance for Electric Utility Steam Generating Units*	EU 58

Consent Decree

Consent Decree filed on March 17, 2009 in U.S. District Court for the Eastern District of Kentucky, Central Division, Lexington, *United States of America v. Kentucky Utilities Company,* Civil Action No. 5:07-CV-0075-KSF ("Consent Decree" or "CD")

Air Toxic Analysis

401 KAR 63:020, *Potentially Hazardous Matter or Toxic Substances*
The Division for Air Quality (Division) has reviewed the potentially hazardous matter or toxic substances that may be emitted by the facility based upon the process rates, material formulations, stack heights and other pertinent information provided by the applicant. Based upon this information, the Division has determined that the conditions outlined in this permit will assure compliance with the requirements of 401 KAR 63:020.

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.
3	Y	Y	Y	Yes*
23-29	N	Y	Y	No
58	Y	Y	Y	Yes*
55-57	N	N	N	No
59 & 60	Y	N	N	No
41-44	N	N	N	No
45-48	N	N	N	No
49, 51, 52, 71, & 72	N	N	N	No
61 & 62	N	N	N	No
7 & 35	N	N	N	No
9	Y	N	N	No
13 & 16	Y	N	Y	No
30-34	N	N	N	No
50	N	N	N	No
38	N	N	N	No
63	Y	N	N	No
64	Y	N	N	No
65	Y	N	N	No
66 & 67	Y	N	N	No
68	Y	N	N	No
69	Y	N	N	No
70	Y	N	N	No

* If Yes, CAM applies for any of the emission units above, 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 Y/N
V-03-034	Renewal	50118 (E992)	2/14/1997	3/1/2005	Title V Renewal	PSD
V-10-004	Renewal	APE20090002, APE20100001	10/04/2010	2/15/2011	Title V Renewal, Consent Decree Requirements, SCR for Emission Unit 3	PSD
V-10-004 R1	Admin Amendment	APE20110001	7/15/2011	7/22/2011	Clarify engine standards	N
V-10-004 R2	Minor Revision	APE20130001	5/9/2013	8/23/2013	Construct and operate new control equipment for Emission Unit 03 and new dry ash and gypsum disposal system	N
V-17-030	Renewal	APE20150005	12/10/2015	6/8/2019	Title V Renewal	N
V-17-030 R1	Minor Revision	APE20200004	3/11/2021	7/16/2021	Modified descriptions for EUs 23-28	N

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
AVO	– Audio/Visual/Olfactory
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
GCOP	– Good Combustion & Operating Practices
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