EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 42

RESPONSIBLE PARTY: Jerry Purvis

Request 42. Refer to the Direct Testimony of Jerry Purvis, p. 11 line 21 to p. 12 line 2. State whether EKPC has submitted the referenced air permit application to the Kentucky Division of Air Quality. If so, produce that application, including any exhibits or attachments. If not, identify by when EKPC plans to submit the application, and produce it upon submittal.

Response 42. EKPC is preparing the air application to the KY Division for Air Quality. The timeline to submit is in January / February 2025. The application will be available on KDAQ's website.

April 24, 2025 Update

Please see the attached PSD Permit Application submitted to the Kentucky Division of Air Quality.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST	**)**
KENTUCKY POWER COOPERATIVE, INC. FOR	**)**
1) CERTIFICATES OF PUBLIC CONVENIENCE	**) CASE NO.**
AND NECESSITY TO CONSTRUCT A NEW	**) 2024-00370**
GENERATION RESOURCES; 2) FOR A SITE	**)**
COMPABILITY CERTIFICATE RELATING TO	**)**
THE SAME; 3) APPROVAL OF DEMAND SIDE	**)**
MANAGEMENT TARIFFS; AND 4) OTHER	**)**
GENERAL RELIEF	**)**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Jerry Purvis, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to Joint Intervenor's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Jerry Purvis

Subscribed and sworn before me on this 24th day of April, 2025.

Gwyn M Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

EAST KENTUCKY POWER COOPERATIVE

January 27, 2025

Michael Kennedy
Director
Division for Air Quality
300 Sower Boulevard, 2nd Floor
Frankfort, Kentucky 40601

Re: Combined Prevention of Significant Deterioration ("PSD")/Title V Permit Application for the Installation and Operation of a Natural Gas-Fired Combined Cycle Gas Turbine and the Modification of Unit #2 to Enable Natural Gas Firing or Co-Firing ("Cooper Project")
John Sherman Cooper Station, AI# 3808
Burnside, Pulaski County, Kentucky

Dear Director Kennedy:

East Kentucky Power Cooperative, Inc. ("EKPC") is pleased to submit a combined Prevention of Significant Deterioration ("PSD")/Title V air permit application for major modifications (the "Cooper Project") at its John Sherman Cooper Station located in Burnside, Pulaski County, Kentucky. Pulaski County is in attainment or unclassifiable for all criteria pollutants.

The Cooper Project consists of (1) the construction and operation of a two-on-one (2x1) natural gas-fired Combined Cycle Gas Turbine ("CCGT") electric generating unit ("EGU") (the "CCGT EGU Project"); and (2) the modification of the existing Unit 2 coal-fired boiler to enable natural gas firing or co-firing with coal (the "C2 Co-Firing Project"). The proposed CCGT EGU Project is a nominal 745 net megawatt CCGT EGU that will consist of two natural gas and fuel oil-fired combustion turbines and ancillary equipment to produce steam for the generation of electricity. an. The Proposed C2 Co-Firing Project will modify Unit 2 to add the capability for the unit to fire 100% natural gas or a combination of natural gas and coal while retaining the capability to fire 100% coal from all burners. EKPC also plans to install ancillary equipment to support the Unit 2 NG co-firing modification.

Please contact me if you have questions regarding the Cooper Project. We look forward to working with you.

Sincerely,

Jerry Purvis

Jerry Purvis, Vice President, Environmental Affairs
East Kentucky Power Cooperative

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Winchester, Kentucky 40392
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cc: D. Mosier, COO & EVP, EKPC, via email
D. Samford, General Counsel, EKPC, via email
C. Johnson, SVP Production, EKPC, via email
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K. Moore, EKPC, via email
N. Saniti, Trinity Consultants, via email
J. Cave, Stites & Harbison, via email

PSD PERMIT APPLICATION

Cooper Project / Somerset, KY

A Touchstone Energy Cooperative

East Kentucky Power Cooperative / J.S. Cooper Station

Prepared By:

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January 24, 2025

Project 241801.0040

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. APPLICATION SUMMARY

East Kentucky Power Cooperative Inc. (EKPC) is a not-for-profit, member-owned generation and transmission cooperative headquartered in Winchester, Kentucky. EKPC owns and operates the John Sherman Cooper Station (Cooper Station), an electricity generating facility located in the Burnside community of Pulaski County, Kentucky. The facility is classified as a major source under both the Title V permit program and the Prevention of Significant Deterioration (PSD) construction permitting program and currently operates in accordance with Title V Permit No. V-18-027, issued by the Kentucky Division for Air Quality (KDAQ or Division) on September 7, 2020, and expiring on September 7, 2025.

EKPC is proposing to install and operate a two-on-one (2x1) natural gas-fired Combined Cycle Gas Turbine (CCGT) electric generating unit (EGU) at Cooper Station (herein labeled as the CCGT EGU Project). Separately, EKPC also plans to modify an existing coal-fired boiler (Cooper Station Unit #2, or C2) to enable natural gas (NG) firing or NG co-firing with coal (herein labeled as the C2 Co-Firing Project). Each proposed project will be defined as a major modification to an existing major stationary source and subject to the New Source Review (NSR) permitting program.

Pursuant to 401 KAR 51:017, Section 1, a project at an existing major stationary source located in an area designated as attainment or unclassifiable that meets the definition of a *major modification* [refer to 401 KAR 51:001 Section 1(114)] is required to conduct a PSD permitting review, including a Best Available Control Technology (BACT) analysis (401 KAR 51:017 Section 8), a Source Impact Analysis (401 KAR 51:017 Section 9), an Air Quality Analysis (401 KAR 51:017 Section 11), and an Additional Impacts Analysis (401 KAR 51:017 Section 13). Through this application containing all required elements under Kentucky Administrative Regulations (KAR) 401 KAR 52:020 and 401 KAR 51:017, EKPC is seeking an issuance of a PSD construction permit and a significant permit revision (SPR) to the Title V permit authorizing the planned installation and operation of the proposed project.

The CCGT EGU Project and the C2 Co-Firing Project are separate "projects" for PSD review. The two Projects are not substantially related because they take place at different locations on the plant site, have no functional relationship, and are being financed and developed as separate projects by the Rural Utilities Services. However, EKPC chose to include both projects in one PSD permit action, herein labeled as the "Cooper Project."

1.1 Cooper Project Overview and Purpose

EKPC, a non-profit, provides generation, transmission and other related services to 16 owner-member cooperatives who supply 520,000 homes, farms, and businesses or about 1.2 million across 89 counties in predominantly rural areas of Kentucky. Reliable and affordable power is critical to EKPC's owner member cooperatives. Unprecedented changes to the bulk power system are causing documented reliability challenges, yet Kentucky's growing economy continues to increase the demand for power. Earlier this year, the EPA proposed a comprehensive set of new, impactful environmental regulations targeting the power sector, including the Clean Air Act Section 111 Greenhouse Gas rule. The North American Electric Reliability Corporation ("NERC") finds that the EPA regulations, when finalized, have the potential to exacerbate the sufficiency of electricity resources to meet demand. These emerging issues have converged to create substantial financial and reliability risks if EKPC does not act swiftly to retrofit and add to its generation portfolio. Indeed, demand cannot be met with unhedged power purchases, which the Kentucky Public Service Commission has determined do not meet a utility's legal obligation to provide adequate, efficient and reasonable service.

To ensure reliable and affordable energy, EKPC is proposing the Cooper Project which consists of the CCGT EGU Project and the C2 Co-firing Project.

- The proposed CCGT EGU Project is a nominal 745 net megawatt (MW-n) CCGT EGU that will consist of two NG- and fuel oil (FO)-fired combustion turbines and ancillary equipment to produce steam for the generation of electricity.
- The Proposed C2 Co-Firing Project will modify C2 to add the capability for the unit to fire 100% NG or a combination of NG and coal while retaining the capability to fire 100% coal from all burners. EKPC also plans to install ancillary equipment to support the C2 NG co-firing modification.

The proposed Cooper Project will allow EKPC to continue meeting the energy and capacity needs of its 16 rural owner- member cooperatives and to support the projected increased winter grid demands, particularly during peak demand periods and when renewable energy sources are unavailable or insufficient to meet demand. EKPC strives to serve Kentucky's growing demand for electricity, reduce the cooperative's carbon footprint, and safeguard reliable power generation capacity at competitive rates. Maintaining the future reliability of the interconnected electric system is essential, and conventional generation resources will be required to facilitate the transition to intermittent renewable resources.

One of EKPC's strategic objectives is to actively manage its current and future asset portfolio to safely deliver reliable, affordable, and sustainable energy from appropriately diversified resources, and to work with federal and state stakeholders to ensure high reliability and economic viability while mitigating evolving regulatory challenges. The Cooper Project as proposed is a key component to EKPC's ability to accomplish that objective. It provides for greater fuel flexibility to keep rates as affordable as possible, while ensuring rural communities in Kentucky have access to reliable power even during extreme weather events.

Additionally, Cooper Station is a critical asset due to its location in rural, south-central Kentucky, serving a transmission constrained area. Cooper Station provides key voltage support in the transmission area throughout southern Kentucky, where the current transmission system is not configured to support the peak load periods in that region without the generation injections at Cooper Station. The proposed Cooper Project will facilitate Cooper Station's ability to continue to provide that support.

1.2 Air Permitting Program Applicability and Project Timeline

Pulaski County is currently designated as an attainment or unclassified area for all criteria pollutants with respect to the National Ambient Air Quality Standards (NAAQS).[1] The facility is currently classified as an existing major stationary source under the PSD permitting program. The CCGT plant will be constructed and operated within the existing Cooper Generating Station property, will have the same standard industrial classification (SIC) code as existing operations, and will be under the same common control and/or ownership. As such, the construction of the CCGT plant will also be a *modification* to an existing major stationary source. With the changes necessary to enable NG co-firing, the C2 Co-Firing Project will be a *modification* to an existing emission unit at a major stationary source. Therefore, the applicability of the PSD permitting program is evaluated for the Cooper Project to assess the PSD triggering status of the overall project emissions increases for regulated NSR pollutants.

As documented herein, this application contains calculated emissions developed using the sum of potential emissions from new emission units and the differences between projected actual and baseline actual

[1] 40 CFR 81.318

emissions (BAE) for existing emission units. This analysis revealed significant emission increases associated with the Cooper Project for the following regulated NSR pollutants: particulate matter (PM), PM 10 microns or less in diameter (PM_{10}), PM 2.5 microns or less in diameter ($PM_{2.5}$), oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfuric acid (H_2SO_4) mists, and greenhouse gases (GHG). Therefore, the Cooper Project is subject to the PSD permitting requirements for these regulated NSR pollutants. To ensure PSD review for sulfur dioxide (SO_2) emissions is not triggered by the Cooper Project, EKPC is proposing a synthetic minor limit so that future actual SO_2 emissions from the Projects do not exceed the 40 ton per year (tpy) significant emission rate (SER). Aside from these regulated NSR pollutants, the Cooper Project will not result in significant emissions of any other regulated pollutants, and since the project emissions increases of all other regulated NSR pollutants fall below the triggering thresholds, explicit PSD avoidance permit limits are unnecessary for those pollutants.

Emission units associated with the project will be subject to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and several Kentucky State Implementation Plan (SIP) air quality regulations. The facility is currently classified as a major source of hazardous air pollutants (HAPs) and will retain this classification following the completion of the project.

To satisfy EKPC's mandate and obligations to provide safe, reliable electrical power to the market, it is important that construction authority for this project be obtained in a timely manner. EKPC is targeting the following dates for construction and commercial operation:

- **January 1, 2027** for the start of construction of new units associated with the CCGT EGU Project
- **February – December 2030** for commercial operation of new units associated with the CCGT EGU Project
- **February 2028** for the start of construction of the necessary modifications and new units associated with the C2 Co-Fire Project
- **May 2029** for commercial operation of the necessary modifications and new units associated with the C2 Co-Fire Project

However, if the NG pipeline to the site is online sooner than anticipated, the commercial operation date (COD) and construction dates would also be moved up.

1.3 Air Quality Analysis

The modeling analyses performed for the project include an evaluation of ambient impacts due to the Cooper Project in the area surrounding the existing Cooper Station, which is designated as a Class II area, and regional Class I areas within 300 km. The Class II analyses provided in **Volume 2** demonstrate that the project will not cause or contribute to an exceedance of any NAAQS or any Class II PSD Increments. In the Class I analysis also provided in **Volume 2**, compliance is demonstrated for the applicable Class I PSD Increments. Additionally, per Federal Land Manager (FLM) guidance, no Air Quality Related Values (AQRV) analysis is required. An Additional Impacts Analysis, consisting of an assessment of growth associated with the proposed project, an assessment of potential impacts of the proposed project on soils and vegetation, and a Class II visibility analysis, is also included in **Volume 2** of this application.

1.4 Organization of Air Permit Application

Volume 1 of the permit application is organized as follows:

- **Section 2** includes a detailed process description of the proposed process operations for the project.

- **Section 3** includes a detailed description of the underlying emissions calculation methodologies used to determine the project emissions increase (PEI) and to define the potential to emit (PTE) for new and modified units.
- **Section 4** provides a discussion of the NSR applicability assessment.
- **Section 5** includes a detailed regulatory applicability analysis.
- **Sections 6** through **Section 9** provide a complete top-down BACT analysis.
- **Section 10** provides a summary of proposed BACT.
- **Appendix A** provides an area map, site layout diagram, and project-wide process flow diagrams.
- **Appendix B** provides an inventory of existing and new emission units at the facility, calculations of potential emissions from new emission units, emission increase calculations for existing emission units associated with the project, and a project emission increase summary for evaluating PSD applicability.
- **Appendix C** includes a complete set of DEP7007 series application forms covering the proposed project.
- **Appendix D** and **Appendix E** provide supporting BACT documentation.
- **Appendix F** provides suggested permit edits to the current Title V permit.

2. PROPOSED PROJECTS AND OPERATIONS DESCRIPTIONS

This section describes the Cooper Project that will be installed and operated at Cooper Station.

2.1 Proposed Facility Location

Figure A-1 in **Appendix A** shows the facility location and the surrounding area on a topographical map. The Universal Transverse Mercator (UTM) coordinates of Cooper Station's center are (approximately) 714.399 km East and 4,097.352 km North (Zone 16, NAD83). Figure A-2 and Figure A-3 in **Appendix A** show the proposed layout of new CCGT EGU Project units and proposed layout of new and modified C2 Co-Firing Project units, respectively. Both figures overlay the new/modified units on existing facility satellite imagery for reference.

2.2 Proposed CCGT EGU Project

This section describes aspects of the proposed Cooper Project associated with the CCGT EGU Project, including proposed operations and equipment.

2.2.1 CCGT EGU Project Overview

With this application, EKPC will install and operate a 2x1 F-Class CCGT Unit. EKPC will utilize and optimize the current electrical transmission system, as well as tap into a "to-be-constructed" NG pipeline that will serve the project. EKPC also plans to install various ancillary equipment to support the CCGT Unit operations, including the following:[2]

- One NG-fired Auxiliary Boiler (EU20) rated at 78.32 MMBtu/hr (HHV),
- Two (2) fuel gas (dewpoint) heaters (EU23 & EU24) rated at 9.13 MMBtu/hr each,
- One 1.25-MW emergency generator with diesel-fired engine (EU21),
- One 310-bhp emergency use diesel-fired fire pump engine (EU22),
- One 9-cell mechanical draft cooling tower (EU25),
- Two (2) 1.66-million gallon (MMgal) ULSFO storage tanks (EU26A & EU26B) to serve both CTs, as well as a 1,000-gallon and 350-gallon diesel storage tank (EU27 & EU28) serving the emergency engines,
- Up to 15 circuit breakers (EU30 & EU31) which contain sulfur hexafluoride (SF_6),
- NG piping components (EU33),
- Seven (7) NG-fired HVAC units rated at 5.5 MMBtu/hr each and 14 NG-fired HVAC units rated at less than 1 MMBtu/hr each (EU29A/B),
- Additional paved haul roads and traffic (EU32),
- One 19% aqueous ammonia storage tank (IA-29), and
- One 93% sulfuric acid storage tank (EU34).

2.2.1.1 CT Units 3 and 4 (EU18 and EU19)

2.2.1.1.1 <u>Description of CT Units</u>

The proposed CCGT Unit will consist of two (2) NG-fired CTs (EU18 Unit 3 CT and EU19 Unit 4 CT) with capability to fire ULSFO (with a maximum sulfur concentration of 15 ppm), and each with their own HRSG arranged in a two-on-one configuration to a single steam turbine (ST) generator. This configuration will not

[2] The equipment ratings listed are based on preliminary engineering designs.

use duct burners. EKPC will install CTs manufactured by Siemens. The CCGT Unit will have a nominal power output of approximately 745 MW-n. Each CT will have a rated heat input capacity on NG and FO of 2,734 MMBtu/hr and 2,597 MMBtu/hr HHV, respectively.

As illustrated in Figure A-4 in **Appendix A**, in a combined cycle process, ambient air is drawn into the compressor section of the CT through an inlet air filtration system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity (RH) to further enhance the overall production capability of the CT. After the evaporative cooling (EC) section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion section of the CT.

The compressor section of the CT, commonly referred to as the gas generator section, generates emissions from the fuel combustion process. A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator section combustion gases expand through the stages of the power turbine where thermodynamic energy is converted to mechanical power. This mechanical power is then transmitted through the rotation of the shaft to the generator of the CT, which is directly coupled to the power turbine. The generator takes this rotational power and converts it to electricity.

The hot combustion gases that are produced in the CT are directed into the HRSG through an exhaust transition duct where waste heat is captured and converted into steam energy before the exhaust gases exit the vertical stack. The steam produced in the HRSG is used by a shared ST to produce additional electrical power. The steam turbine does not generate emissions out of a stack. Once mechanical work from the steam is captured, the steam is exhausted and subsequently condensed in a vacuum within a condenser. The condensate is reused as feed water to the HRSG, creating a closed-loop system.

The proposed CCGT Unit is designed for continuous operations. The CT will be capable of operating between a nominal minimum emissions compliance load (MECL) and 100-percent load. MECL is defined as the minimum steady-state load at which the combustion turbine can operate at any given ambient condition and maintain compliance with all emission limits.

The operational scenarios used to establish the maximum short-term and annual emissions are discussed in Section 3 of the application. As presented on the DEP 7007N form in **Appendix C**, the CTs will be capable of operating up to 8,760 hr/yr on NG and up to 1,080 hr/yr on FO.

2.2.1.1.2 Air Pollution Controls

The CT vendor, Siemens, will install dry-low-NO_X combustors (DLN) that will operate while combusting NG and water injection while combusting FO in the CT. The turbines will all be equipped with oxidation catalysts and selective catalytic reduction (SCR) as add-on controls to reduce stack NO_X, CO, VOC, and organic HAP emissions.

2.2.2 NG-Fired Auxiliary Boiler (EU20)

The NG-fired Auxiliary Boiler will be permitted with a rated heat input capacity of 78.32 MMBtu/hr. The Auxiliary Boiler will only serve process loads that consist of the following:

- HRSG freeze protection (only required with the unit off-line and ambient with potential freezing)
- Unit starts under warm or cold start conditions. The Auxiliary Boiler steam will provide sparging steam to the HRSG and condenser as well as seal steam for the ST. After the combined cycle unit is up and

running, auxiliary steam is furnished by the HRSG (cold reheat) and the Auxiliary Boiler can be taken out of service.

The Auxiliary Boiler will be equipped with an oxidation catalyst system and ultra low-NO_X burners (ultra LNBs), and will be capable of operating up to 8,760 hours per year.

2.2.3 Emergency Generator with Diesel-Fired Engine (EU21)

The project will employ a 1.25-MW emergency generator that will include a nominal 2,220 bhp compression ignition engine. Ultra-low sulfur fuel oil (ULSFO) with a maximum sulfur content of 0.0015 weight percent (or 15 ppm) will be used in the engine. Potential emissions are based on operating 500 hr/yr in accordance with KDAQ permitting practices, although there are no hourly limits on an emergency engine when operating for emergency purposes.

2.2.4 Emergency Diesel-Fired Fire Pump Engine (EU22)

The project will include a 310-bhp diesel-fired compression ignition engine for emergency purposes to supply energy to the fire pump. ULSFO will be used in the engine. Potential emissions are based on operating 500 hr/yr in accordance with KDAQ permitting practices, although there are no hourly limits on an emergency engine when operating for emergency purposes.

2.2.5 Fuel Gas (Dewpoint) Heaters (EU23 and EU24)

Two NG-fired fuel gas (dewpoint) heaters with a rated heat input of 9.13 MMBtu/hr each will be used, as needed, to heat the NG that will be introduced to the combustion turbine. Both units will utilize LNBs and will be capable of operating up to 8,760 hours per year.

2.2.6 Cooling Tower (EU25)

Steam exiting the ST will be condensed via indirect heat transfer using cooling water provided by a mechanical draft, nine-cell, back-to-back counter-flow wet cooling tower. Cooling tower drift will be minimized to 0.0005% of the design recirculation rate or less using inherent drift eliminators.

2.2.7 Fuel Oil Storage Tanks (EU26A/B, EU27, and EU28)

EKPC will construct two (2) FO storage tanks (proposed EU26A and EU26B) with large enough capacities to accommodate a worst-case scenario of 72 straight hours of FO firing within both turbines simultaneously primarily during periods of NG curtailment. The estimated working capacities of these two FO storage tanks are expected to be 1.66 million gallons each.

Additionally, the standby generator engine will be furnished with a base mounted dual wall tank with a capacity of 1,000 gallons (proposed EU27), and the diesel-fired emergency fire pump engine will have an integrated 350-gallon dual wall tank located within the fire pump enclosure (proposed EU28).

2.2.8 Natural Gas-Fired HVAC Heaters (EU29)

EKPC plans to provision multiple NG-fired HVAC units within buildings that support the CCGT Project. The HVAC systems in the new buildings will be supported by seven (7) NG-fired heaters rated at 5.5 MMBtu/hr each and 14 NG-fired heaters rated at 0.061 MMBtu/hr each. For permitting purposes, EKPC has included all 21 NG-fired HVAC heaters under one proposed emission unit (proposed EU29).

2.2.9 Circuit Breakers (EU30 and EU31)

Three (3) turbine circuit breakers (proposed EU30) and 12 switchyard station circuit breakers (proposed EU31) will be installed to serve the new CCGT. Each turbine circuit breaker will be rated at 20 kilovolts (kV) and contain 30 lbs of SF_6, and each switchyard station circuit breaker will be rated at 170 kV and contain 58 lbs of SF_6.

2.2.10 New Haul Road Traffic (EU32)

The operation of the new emission units constructed as part of the CCGT Project will necessitate an increased amount of delivery truck traffic. Existing and new paved roads will be used to transport various chemicals throughout Cooper Station. The paved routes will mitigate fugitive emissions. Since natural gas will be delivered via pipeline, no natural gas truck deliveries are estimated, further mitigating fugitives. The following paved routes constitute the new haul road traffic to be permitted as EU32:

- 19% Aqueous Ammonia Delivery
  - Approximately 0.79 miles/trip and 275.6 total vehicle miles traveled (VMT) per year
- ULSFO Delivery
  - Approximately 1.37 miles/trip and 5,835 VMT/yr
- Water Treatment Building Chemicals Delivery
  - Approximately 1.12 miles/trip and 91.74 VMT/yr
- Cooling Tower Chemicals Delivery
  - Approximately 1.39 miles/trip and 12.78 VMT/yr

2.2.11 Natural Gas Piping Fugitives (EU33)

Cooper Station will be constructing new components to connect to the offsite NG pipeline to provide the requisite fuel for all NG-fired units to be installed as part of the project. The construction of the piping will include the installation of various equipment leak components which will be sources of fugitive emissions (proposed EU33). EKPC will be installing *approximately* 200 valves, 16 pressure relief valves (PRVs), 280 flanges, and two (2) sampling connections in NG service. These piping components are potential sources of carbon dioxide, methane, and VOC.

2.2.12 Sulfuric Acid Storage Tank (EU34)

EKPC will install one 3,000-gallon storage tank storing an aqueous solution of sulfuric acid. The aqueous solution will contain approximately 93% by weight sulfuric acid. The sulfuric acid solution will be used as a water treatment chemical. Cooper Station will consume approximately 20,000 gallons of this 93% sulfuric acid solution per year.

2.3 Proposed C2 Co-Firing Project

This section describes aspects of the proposed Cooper Project associated with the C2 Co-Firing Project, including proposed operations and equipment.

2.3.1 C2 Co-Firing Project Overview

A separate project will be implemented to modify C2 to burn both coal and/or NG. C2 and its associated controls [LNBs, dry flue gas desulfurization (DFGD), SCR, pulse-jet fabric filter (PJFF), and FuelSolv treatment] will remain in operation after the CCGT EGU is in operation. With the C2 Co-Firing Project, EKPC will initiate on-site construction and installation of boiler modifications necessary to enable NG co-firing. C2 will be modified to fire 100% NG, co-fire coal and NG at various levels, and will retain the ability to fire 100% coal based on economics or for reliability.

The original equipment manufacturer of the Cooper unit 1 and 2 boilers was Babcock & Wilcox. EKPC has selected Babcock & Wilcox (B&W) as the gas technology provider. B&W provides a retractable "spud" style NG burner for adding NG firing capability while maintaining the ability to switch between coal and NG firing modes of a single burner at any time. The spud burner design supports EKPC's operational flexibility requirements for C2. Co-firing is defined as the combustion of two different fuels in the same combustion system. Each burner will be capable of utilizing NG and pulverized coal, but not both fuels simultaneously. Igniters may be operated on a mill group basis either using NG or FO. The supply of FO to the igniters will not be modified as the existing igniter system capacity is not being changed as part of the co-fire retrofitting.

Each of the existing burners will be modified with the addition of a retractable B&W low NO_X Super Spud® assembly inserted through the existing burner guide tube. This will allow gas to be injected into the furnace at the existing burner locations, and will not alter the coal burners. Each coal elbow will be replaced with a new coal elbow designed for incorporating the spud burner gas lance. The retractable spud burner is the only commercial offering from B&W for adding NG firing to their existing coal burner while retaining the ability to fire coal on the same individual burner.

2.3.2 Fuel Gas (Dewpoint) Heater (EU17)

With the C2 modification, a NG-fired fuel gas (dewpoint) heater with a rated heat input of 11.65 MMBtu/hr (EU17) will be required. This indirect heat exchanger will be used to heat the NG that will be introduced into C2. This heater will be capable of operating up to 8,760 hours per year.

2.3.3 Natural Gas Piping Fugitives (EU33)

As described above for the CCGT, adding NG combustion capabilities to C2 requires the installation of various NG piping components such as valves and flanges. The C2 Co-Firing Project will require the installation of approximately 470 valves, 5 PRVs, and 1,700 flanges.

3. EMISSIONS CALCULATION METHODOLOGIES AND SUMMARY

This section summarizes the emission calculation methodologies for the emission sources that comprise the proposed Cooper Project. Within each emissions unit section, the methods used to calculate emissions are discussed, followed by a summary of the emissions estimates for the specific unit and, in the case of the CTs, the mode of operation. The annual potential emissions for regulated NSR pollutants and HAPs from the new units in the Cooper Project are summarized in Section 3 of **Appendix B**. The hourly and annual potential emissions of all affected units are documented in the DEP7007 N Forms provided in **Appendix C**. The potential emissions are used to determine the applicability of certain regulatory requirements as discussed subsequently in Sections 4 and 5.

A more detailed set of documented emission calculations is presented in **Appendix B** of this application for all the new emission units that are part of the CCGT EGU Project and all new/modified emission units that are a part of the C2 Co-Firing Project. The nomenclature for the new emission unit and emission point IDs shown below are placeholders based on the next sequential numbers in the facility's current emission unit inventory and can be finalized by the Division upon its review of the application.

3.1 Combustion Turbine Emissions

3.1.1 CT Units 3 and 4 (EU18 and EU19)

The following subsections present the methodologies used to determine the combustion turbine emissions, including the maximum hourly emissions during steady-state operations and SU/SD events, as well as the total annual emissions including SU/SD emissions.

3.1.1.1 CT Emissions from Steady State Operations

Normal or steady-state operation of a CT is characterized as continuous operation at loads generally in the 35 to 100% range (over the range at which emissions compliance is achieved). The CTs may be operated up to 8,760 hr/yr. As detailed in Section 4 of **Appendix B**, EKPC has calculated annual steady-state potential emissions based on 7,680 hr/yr firing NG, and 1,080 hr/yr firing FO.

Heat input to a gas turbine varies as a function of the fuel (type, composition, and quality), ambient temperature, RH, and evaporative cooling operation. As explained in more detail in Section 4 of **Appendix B**, each individual CT can achieve a rated heat input capacity when firing NG of 2,734 MMBtu/hr (operating at 100% of base load, ambient temperature is 59 °F, and combustion air RH is 72.9%), and a rated heat input capacity when firing FO of 2,597 MMBtu/hr (operating at 100% of base load, ambient temperature is 40.3 °F, and combustion air RH is 37.6%).

3.1.1.1.1 <u>Steady-State Emissions</u>

Emissions from a gas turbine are a function of the fuel (type, composition, and quality), ambient temperature, RH, evaporative cooling operation, as well as inherent controls, add-on controls, chemical conversions, and other miscellaneous factors. As documented in Section 4 in **Appendix B**, maximum hourly controlled and uncontrolled emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4 for the proposed gas turbines rely on the vendor operational data and EKPC's vendor guarantee requirements for the CT units, which are listed in **Table 3-1** below. Emission factors for these pollutants were calculated for both NG and FO firing scenarios as the maximum hourly emissions rate for the specific fuel type divided by the maximum fuel volumetric consumption.[3]

Table 3-1. CT – Basis of Pollutant Emissions Rates

Pollutant	NG Emissions Basis	Maximum NG Steady-State Emission Rate (lb/hr)	FO Emissions Basis	Maximum FO Steady-State Emission Rate (lb/hr)
NO_X	2 ppmvd @ 15% O_2	19.82	4.5 ppmvd @ 15% O_2	46.27
CO	2 ppmvd @ 15% O_2	12.07	2 ppmvd @ 15% O_2	12.52
VOC	1 ppmvd @ 15% O_2	3.46	1 ppmvd @ 15% O_2	3.58
$PM/PM_{10}/PM_{2.5}$[4]	0.5 gr S/100 scf with 100% conversion to $(NH_4)_2SO_4$	17.21	15 ppm S (ULSFO), 100% conversion to $(NH_4)_2SO_4$	30.12
SO_2	0.5 gr S/100 scf	3.67	15 ppm S (ULSFO)	3.94
H_2SO_4	0.5 gr S/100 scf with 100% conversion to H_2SO_4	5.63	15 ppm S (ULSFO), 100% conversion to H_2SO_4	6.03

Source: Maximum rate based on BACT

The CTs will continue to comply with these emission rates irrespective of ambient weather conditions at all loads above MECL. Emissions resulting from SU/SD operations are described in Section 3.1.1.2. Information regarding inherent and add-on controls used in the CT/HRSG system was provided in Section 2.2.1.1.2.

PM emissions include the formation of ammonium salts [e.g., $(NH_4)_2SO_4$]. Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is possible under certain conditions. One pathway is the sulfate formation from H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$, as well as the nitrate formation in the form of NH_4NO_3. All PM is assumed to be less than 2.5 µm in mean diameter.

Annual emissions of SO_2 from NG firing were based on a maximum pipeline sulfur content and additional factors to account for chemical conversions. For SO_2, the emissions are based on an expected maximum sulfur content for the pipeline gas of 0.5 gr/100 scf and 100% conversion from sulfur to SO_2. Annual emissions of SO_2 from FO firing are based on the FO sulfur content (0.0015%) and the AP-42 Section 3.4-1 emission factor for SO_2 emissions. In reality, the total SO_2 emissions will be less due to the fact that some SO_2 further converts to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the potential emissions of SO_2 do not account for these further reductions and thus the emission

[3] As discussed above, EKPC has conservatively chosen the maximum fuel heat input on NG and FO as a basis for fuel consumption in the PTE calculations. To develop site-specific emission factors relative to the volume of fuel consumption, EKPC has chosen a site-specific NG HHV of 1,060 Btu/scf, and a site-specific FO HHV of 136.2 MMBtu/Mgal.

[4] For conservatism, filterable PM emissions are estimated using the same bases as for total PM_{10} and total $PM_{2.5}$.

estimates are conservative, due to the unknown fates of fuel-bound sulfur given the HRSG, SCR and oxidation catalysts as well as the changing ambient temperatures.

Lastly, annual H_2SO_4 emissions from both NG and FO firing were based on a conversion rate of 100% from SO_2 to SO_3 and 100% from SO_3 to H_2SO_4.

3.1.1.1.2 Lead Emissions

Lead emissions from oil firing in the CCGT are based on the factor provided in Table 3.1-5 (for FO) of the U.S. EPA's AP-42 Chapter 3, Section 3.1 *Stationary Gas Turbines*.[5].

3.1.1.1.3 Ammonia Emissions

Ammonia emissions from the SCR have been calculated assuming the ammonia slip post-SCR is no more than 5 ppmvd at 15% O_2.

3.1.1.1.4 Formaldehyde and HAP Emissions

Controlled formaldehyde emissions from both NG and FO combustion are calculated based on an emissions guarantee of 91 parts per billion by volume, dry (ppbvd) at 15% O_2, which is equivalent to the applicable standard in NESHAP Subpart YYYY, 40 CFR §63.6100. This concentration was then converted to a lb/MMBtu emission factor based on a default dry F-factor (Fd) for NG combustion from EPA Reference Method (RM) 19. The uncontrolled emissions factors for formaldehyde were obtained from Table 3.1-3 (for NG) and Table 3.1-4 (for FO) of the U.S. EPA's AP-42 Chapter 3, Section 3.1 *Stationary Gas Turbines*.[6]

The CT's uncontrolled emission factors for other HAPs emitted (other than acetaldehyde) via NG and FO combustion were also based on Tables 3.1-3 and 3.1-4 of AP-42. The background document supporting this chapter provided controlled emissions factors when using a CO catalyst for acetaldehyde, acrolein, and benzene.[7] For other organic HAPs, EKPC applied a nominal VOC control efficiency (CE) afforded by the oxidation catalyst. See Sections 4.3.3 and 4.4.4 of **Appendix B** for additional details and for the derivation of organic HAP control efficiencies.

Lastly, metallic HAPs are expected to be emitted in low concentrations due to FO combustion within the CT. Uncontrolled emission factors for metallic HAPs are based on Table 3.1-5 from AP-42, Section 3.1.

3.1.1.1.5 GHG Emissions

GHG emissions are estimated based on proposed equipment specifications (i.e., rated heat input) as provided by the vendor and the default emission factors in the U.S. EPA's Greenhouse Gas Reporting Program (40 CFR 98, Subpart C, Tables C-1 and C-2 for NG and Distillate FO No. 2/Liquid Petroleum Products). According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show carbon dioxide equivalent (CO_2e) emissions calculated by multiplying the mass of each of the GHG by its associated global warming potential (GWP), which are specified in Table A-1 to Subpart A of 40 CFR Part 98. The GWPs chosen for this PSD analysis are those required to be used for GHG reporting under 40 CFR Part 98 beginning January 1, 2025.[8]

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[5] https://www.epa.gov/sites/default/files/2020-10/documents/c03s01.pdf

[6] Ibid.

[7] https://www.epa.gov/sites/default/files/2020-10/documents/b03s01.pdf

[8] 89 FR 31802, https://www.federalregister.gov/d/2024-07413

3.1.1.2 CT Emissions from Startup and Shutdown Operations

The CT equipment package has its own unique features that allow the CCGT to quickly achieve emissions compliance during a cold, warm, or hot start event. The following provides the underlying basis for the total event estimates on **NG:**

- Cold Start (CS) is preceded by over 48 hours of shutdown (or any warming events). The minimum value of 48 hours is assumed, which allows for a conservatively high number of CS per year.
  - Expected maximum annual CS events = **15** events/yr over a 100 to 290 minute ramp up time. EKPC used **100** minutes per NG CS for conservatism in emission calculations.

- Warm Start (WS) is preceded by a shutdown (or any warming events) between 8 and 48 hours. The minimum value of **8** hours is assumed, which allows for a conservatively high number of WS per year.
  - Expected maximum annual WS events = **365** events/yr over a 70 to 180 minute ramp up time. EKPC used **70** minutes per NG WS for conservatism in emission calculations.

- Hot Start (HS) is defined as taking place within 8 hours of the previous shutdown without any warming provisions. No idling time was incorporated prior to a HS to allow for a conservatively high number of HS per year.
  - Expected maximum annual HS events =**585** events/yr over a 45 to 110 minute ramp up time. EKPC used **45** minutes per NG HS for conservatism in emission calculations.

- A SD occurs for 30-40 minutes and the total number is the sum of all CS, WS, and HS events.
  - Expected maximum annual SD events = **965** events/yr over 30 to 40 minutes until emissions cease. EKPC used **30** minutes per NG SD for conservatism in emission calculations.

The following provides the underlying basis for the total event estimates on **FO**:

- CS is preceded by over **48** hours of shutdown (or any warming events). The minimum value of 48 hours is assumed, which allows for a conservatively high number of CS per year.
  - Expected maximum annual CS events = **15** events/yr over a 110 to 300 minute ramp up time. EKPC used **110** minutes per FO CS for conservatism in emission calculations.

- WS or "non-cold startup" is preceded by a shutdown (or any warming events) between 8 and 48 hours. The minimum value of **8** hours is assumed, which allows for a conservatively high number of WS per year.
  - Expected maximum annual WS events = **15** events/yr over a 75 to 200 minute ramp up time. EKPC used **75** minutes per FO WS for conservatism in emission calculations.

- HS is defined as taking place within 8 hours of the previous shutdown without any warming provisions. No idling time was incorporated prior to a HS to allow for a conservatively high number of HS per year.
  - Expected maximum annual HS events = **30** events/yr over a 45 to 115 minute ramp up time. EKPC used **45** minutes per FO HS for conservatism in emission calculations.

- A SD occurs for 30-40 minutes and the total number is the sum of all CS, WS, and HS events.
  - Expected maximum annual SD events = **60** events/yr over 30 to 40 minutes until emissions cease. EKPC used **30** minutes per FO SD for conservatism in emission calculations.

NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2 emissions during SU/SD events vary from steady state emissions. The total emissions for each event are provided in Section 4.6.1 in **Appendix B**. EKPC is conservatively estimating the maximum number of each type of startup and shutdown event. **Table 3-2** below summarizes the total number of each event, **Table 3-3** summarizes the CO, VOC, and NO_X emissions per event type while firing NG, and **Table 3-4** summarizes the CO, VOC, and NO_X emissions per event type while firing FO. As summarized in **Table 3-5**, the annual emissions from solely NG and FO steady-state operations (i.e., Scenario 1) are higher for all pollutants besides CO, VOC, and NO_X; as such, the emissions per event for other pollutants are not summarized in **Table 3-3** and **Table 3-4**.

Table 3-2. Maximum Annual Startup and Shutdown Events

NG				FO			
Cold Start	Warm Start	Hot Start	Shutdown	Cold Start	Warm Start	Hot Start	Shutdown
15	365	585	965	15	15	30	60

Table 3-3. CCGT Natural Gas Startup and Shutdown Emissions

Event Type	**CO** (lb/event)	**VOC** (lb/event)	**NO_X** (lb/event)
Cold Start	9,358	824	288
Warm Start	4,501	410	159
Hot Start	2,677	253	110
Shutdown	849	64	56

Table 3-4. CCGT Fuel Oil Startup and Shutdown Emissions

Event Type	**CO** (lb/event)	**VOC** (lb/event)	**NO_X** (lb/event)
Cold Start	15,416	1,780	556
Warm Start	7,462	872	310
Hot Start	4,477	530	217
Shutdown	1,215	122	100

3.1.1.3 CT Annual Emissions

The calculations in Section 4 of **Appendix B** detail the methodologies used to determine the annual PTE from the CTs. The calculations presented therein are representative of one of the two CTs.

The following Process IDs have been assigned to each CT:

- Process ID 1: NG Combustion (Steady-State)
- Process ID 2: FO Combustion (Steady-State)
- Process IDs 3-6: NG Startup/Shutdowns
- Process IDs 7-10: FO Startup/Shutdowns

Each of the Process IDs above have been considered in the methodologies used to determine the worst-case annual emissions from each CT. EKPC evaluated the following scenarios to determine a "worst-case" emissions profile:

- Scenario 1
  - 7,680 hr/yr NG steady-state
  - 1,080 hr/yr FO steady-state
  - No SU/SD events

- Scenario 2
  - 4,306 hr/yr NG steady-state
  - 861 hr/yr FO steady-state
  - 15 NG Cold Starts/yr
  - 365 NG Warm Starts/yr
  - 585 NG Hot Starts/yr
  - 965 NG Shutdowns/yr
  - 15 FO Cold Starts/yr
  - 15 FO Warm Starts/yr
  - 30 FO Hot Starts/yr
  - 60 FO Shutdowns/yr
- Scenario 3
  - 8,760 hr/yr NG steady-state
  - No FO steady-state
  - No SU/SD events

Table 3-5 below summarizes the annual emissions for NSR-regulated air pollutants from each of the three scenarios outlined above for one turbine. Annual emissions of additional pollutants are summarized in Section 4.9 of **Appendix B**.

Table 3-5. Annual Emissions from Each Scenario (tpy)

Pollutant	Scenario 1 Steady State NG/FO	Scenario 2 Steady-State NG/FO with SU/SD Events	Scenario 3 Steady State NG
NO_X	101.1	164.6	86.8
CO	53.1	2,390.2	52.9
VOC	15.2	226.2	15.1
$PM/PM_{10}/PM_{2.5}$	82.4	54.8	75.4
SO_2	16.2	10.6	16.1
H_2SO_4	24.9	14.8	24.6
Lead	0.020	0.016	0
CO_2e	1,437,622	843,066	1,374,685

For the detailed annual emissions derivations for each of the three scenarios outlined above, refer to Section 4 of **Appendix B**.

For all other pollutants besides those with hourly emission rates based on vendor-provided data (e.g., ammonia, organic HAP, metallic HAP), EKPC used the reference emission factors described in Section 3.1.1.1, converted to a fuel volume-based emission factor as needed, and multiplied by the annual NG and FO steady-state operating hours detailed above to arrive at a final annual PTE.

3.2 C2 Co-firing Project

The following subsections present the methodologies used to determine the maximum hourly emissions during steady-state operations while C2 is co-firing coal/NG or combusting 100% NG, as well as the worst-case annual emissions from both operating scenarios. The subsections below detail the emission factor derivations and hourly/annual emissions calculations. The emission factors derived using the methodologies below are used in conjunction with additional methodologies employed to develop the components of the NSR applicability assessment, which are described further in Section 4.

3.2.1 C2 Coal Combustion Emission Factors

To determine the emissions profile from co-firing coal/NG, EKPC first revisited existing emission factors for coal combustion that have been used to populate the annual Kentucky Emissions Inventory System (KyEIS) Web Survey. EKPC has evaluated the reliability of the emission factors used to populate the Web Survey and updated these emission factors when appropriate to more accurately account for permitted emissions limitations or, in the absence of a reliable emission factor from the KyEIS, utilize appropriate emission factor derivation methodologies from reference documentation such as AP-42.

3.2.1.1 NO_X, SO_2, and PM Emission Factors

EKPC has developed uncontrolled emission factors for NO_X, SO_2, and PM based on AP-42, Section 1.1 for bituminous coal combustion. AP-42 Table 1.1-3 provides an uncontrolled emission factor for NO_X of 11 lb/ton for pre-NSPS, pulverized coal, dry bottom, wall-fired coal combustion units with LNBs like C2. The uncontrolled SO_2 emission factor for the same type of coal combustion unit is defined as the sulfur content of the coal (in weight percent) multiplied by 38. Similar to SO_2, AP-42 Table 1.1-4 provides an equation for deriving the uncontrolled emission factor for filterable PM. The uncontrolled filterable PM emission factor for coal combustion units like C2 is calculated as the ash content of the coal (in weight percent) multiplied by 10. As shown in Section 21.3.2 of **Appendix B**, all emission factors have been converted to a heat input basis using the relevant coal HHV.

For the purposes of fully detailing the process starting at an uncontrolled emission factor, determining a CE, and arriving at a controlled emission factor, EKPC has included the uncontrolled emission factors above in Section 21.3.2 of **Appendix B**. However, the values that drive the annual NO_X and SO_2 PTE calculations are based on permitted emissions limitations. The following emissions limitations apply to C2 and have been used as surrogates for the controlled emission factors for NO_X and SO_2:

- NO_X: 0.080 lb/MMBtu on a 30-day rolling average basis (per Consent Decree entered September 24, 2007, paragraph 53)
- SO_2: 30-day Rolling Average SO_2 Removal Efficiency of at least 95 percent or a 30-Day Rolling Average SO_2 Emission Rate of no greater than 0.100 lb/MMBtu (per Consent Decree entered September 24, 2007, paragraph 65)

The controlled filterable PM emission factor is set to the proposed PM BACT limit of 0.010 lb/MMBtu (see Section 8.3 for additional details regarding the PM BACT analysis for C2). To calculate the uncontrolled emission factors for filterable PM_{10} and filterable $PM_{2.5}$, EKPC applied the appropriate cumulative mass fractions from AP-42, Table 1.1-6, for pulverized coal-fired boilers equipped with a baghouse. The cumulative mass fraction for filterable PM_{10} is 92% (which equates to an uncontrolled emission factor of 110.4 lb/ton), and that for filterable $PM_{2.5}$ is 53% (uncontrolled emission factor of 63.6 lb/ton). Applying the same CE as that derived for total filterable PM and a coal HHV of 26 MMBtu/ton – the default HHV provided by AP-42, Section 1.1 – the controlled emission factors for filterable PM_{10} and filterable $PM_{2.5}$ are 0.009 lb/MMBtu and 0.005 lb/MMBtu, respectively.

EKPC has accounted for contributions from CPM species by using the controlled emission factor of 0.02 lb/MMBtu from AP-42, Table 1.1-5 [total CPM from pulverized coal-fired boilers with PM controls combined with circulating semi-dry scrubber (CDS)]. For the purposes of calculating total PM_{10} and total $PM_{2.5}$

emissions, EKPC assumed that the aerodynamic particle diameter of all CPM species are less than 2.5 microns. As such, the controlled emission factors for total PM species have been calculated as follows:

- Total PM_{10} = 0.009 lb/MMBtu + 0.02 lb/MMBtu = 0.029 lb/MMBtu
- Total $PM_{2.5}$ = 0.005 lb/MMBtu + 0.02 lb/MMBtu = 0.025 lb/MMBtu

Controlled actual filterable PM emission factors are documented based on the annual source test results included within the selected baseline period. The same AP-42 Chapter 1.1 filterable PM particle size data and CPM emission factors applied in the derivation of the potential total PM_{10} and $PM_{2.5}$ emission factors are used to calculated controlled, actual total PM_{10} and $PM_{2.5}$ emission factors in conjunction with the stack test-based, actual PM emission factor.

For the purposes of conducting the PSD applicability analysis, controlled actual SO_2 emission factors are derived based on the average emission rate measured by the SO_2 CEMS during the baseline period as documented in Section 22.3 of **Appendix B**.

3.2.1.2 H_2SO_4 Emission Factor

The uncontrolled SO_2 emission factor forms the basis for the uncontrolled H_2SO_4 emission factor. While excluded from the SO_2 emission factor derivation, a small fraction of the total SO_2 emissions will oxidize to SO_3 and then further react to form H_2SO_4. To estimate the amount of H_2SO_4 emitted relative to SO_2 emissions, EKPC referenced the model developed by the Electric Power Research Institute (herein referred to as the EPRI model).[9] The EPRI model estimates the total releases of H_2SO_4 as a function of SO_2 emissions and a series of conversions and correction factors. The overall conversion from SO_2 to H_2SO_4 has been estimated as 0.148%, and the heat input-based emission factor – assuming a project-specific coal heating value of 25.32 MMBtu/ton – is 0.005 lb/MMBtu.

3.2.1.3 Lead Emission Factor

Lead emission factors are based on AP-42, Section 1.1. Additionally, EKPC applied a CE afforded by the PJFF of 99.74% to the uncontrolled emission factor.[10]

3.2.1.4 Ammonia Emission Factor

As described previously for ammonia emissions from the new CTs, ammonia slip from C2 is expected due to operating the SCR system. EKPC calculated an uncontrolled emission factor for ammonia assuming an ammonia slip concentration in the stack exhaust of 6 ppmvd at 15% O_2.[11] The derivation of the uncontrolled emission factor is described in Section 21.3.3 of **Appendix B**.

3.2.1.5 CO, VOC, and HAP Emission Factors

EKPC used the uncontrolled emission factors (in lb/ton) for CO, VOC, and select organic and metallic HAP from AP-42, Section 1.1. Additionally, EKPC applied a CE afforded by the CDS system of 98.12% to the

[9] *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398

[10] Control efficiencies for HCl, HF, and metallic HAP are equal to those listed in the RY2022 DAQ-accepted KyEIS Web Survey.

[11] Average of typical permitted ammonia slip, per EPA's Air Pollution Control Technology Fact Sheet for SCR systems. https://www.epa.gov/sites/default/files/2020-08/documents/fscr.pdf

uncontrolled emission factors for hydrogen chloride (HCl) and hydrogen fluoride (HF), and a CE afforded by the PJFF of 99.74% to the uncontrolled emission factors for all metallic HAP.[12]

3.2.1.6 GHG Emission Factors

GHG emission factors are based on the default emission factors in the U.S. EPA's Greenhouse Gas Reporting Program (40 CFR 98, Subpart C, Tables C-1 and C-2 for Bituminous Coal). CO_2e emissions were calculated by multiplying the mass of each of the GHG by its associated GWP, which are specified in Table A-1 to Subpart A of 40 CFR Part 98. The GWPs chosen for this PSD analysis are those required to be used for GHG reporting under 40 CFR Part 98 beginning January 1, 2025.[13]

3.2.2 C2 Natural Gas Combustion Emission Factors

C2 will have the capability to combust up to 100% NG on a short-term and long-term basis post-modification. As such, EKPC developed emission factors associated with 100% NG combustion to compare to existing coal combustion capabilities as part of the PEI calculations used to determine NSR applicability, which is explained further in **Section 4** of this application. The following subsections summarize the emission factor derivation methodologies for NG combustion.

3.2.2.1 NO_X Emission Factor

EKPC has chosen an uncontrolled NO_X emission factor for NG combustion in C2 post-modification as the pre-NSPS D and Da uncontrolled emission factor from AP-42 Section 1.4, Table 1.4-1 of 280 lb/MMscf. Using the site-specific NG HHV of 1,060 Btu/scf, the uncontrolled emission factor is 0.275 lb/MMBtu. The controlled NO_X emission factor has been set equal to the allowable emission rate of 0.08 lb/MMBtu (see Section 21.4.2 of **Appendix B**).

3.2.2.2 VOC, PM, Lead, and HAP Emission Factors

The uncontrolled emission factors for most other pollutants (besides SO_2, H_2SO_4, CO, and GHG, as explained below) have been selected from AP-42, Section 1.4 for NG Combustion in External Combustion Sources. Section 21.4.2 of **Appendix B** summarizes the selected emission factors. To address a known high bias to the AP-42 Section 1.4 CPM emission factor, total PM_{10} and $PM_{2.5}$ emissions are calculated by applying a filterable to total PM ratio to the AP-42 value for filterable PM. The ratio (0.55) was calculated using data from EPA's SPECIATE database for NG Combustion - Composite with no controls (Profile ID 91112). No control efficiency has been applied to the emissions of VOC, PM, lead and HAP from NG combustion within C2.

3.2.2.3 SO_2 and H_2SO_4 Emission Factors

The uncontrolled SO_2 emission factor for NG combustion in C2 post-modification was derived from a maximum pipeline NG sulfur content of 0.5 gr/100 scf. The emission factor is conservative in that it assumes all sulfur content in the pipeline NG, once combusted in C2, is converted to SO_2. Additional conservatism has been implemented by assuming that no SO_2 is further oxidized to SO_3. Using a project-specific NG HHV of 1,060 Btu/scf, the calculated heat input-based uncontrolled SO_2 emission factor, as presented in Section 21.4.2 of **Appendix B**, is approximately 0.0013 lb/MMBtu.

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[12] Control efficiencies for HCl, HF, and metallic HAP are equal to those listed in the RY2022 DAQ-accepted KyEIS Web Survey.

[13] 89 FR 31802, https://www.federalregister.gov/d/2024-07413

The uncontrolled SO_2 emission factor forms the basis for the uncontrolled H_2SO_4 emission factor. While excluded from the SO_2 emission factor derivation, a small fraction of the total SO_2 emissions will oxidize to SO_3 and then further react to form H_2SO_4. To estimate the amount of H_2SO_4 emitted relative to SO_2 emissions, EKPC referenced the EPRI model. The EPRI model estimates the total releases of H_2SO_4 as a function of SO_2 emissions and a series of correction factors.

The first correction factor is referred to as a Fuel Impact Factor (F1). Table 4-1 of the EPRI model indicates a Fuel Impact Factor of 0.01 is appropriate for NG-fired steam generating units. The second correction factor included in the final conversion calculation is the Technology Impact Factor (F2). EKPC has selected a Technology Impact Factor due to removal of SO_3 and/or H_2SO_4 within the APH primarily due to condensation of H_2SO_4 on the surface of the heat exchanger. Table 4-3 of the EPRI model summarizes the Technology Impact Factors from the APH by fuel type. For the coal combusted in C2, a correction factor of 0.5 is appropriate.

The stoichiometry of the overall reaction converting SO_2 to H_2SO_4 multiplied by the Fuel Impact Factor of 0.01 derives an H_2SO_4 emission factor which is approximately 1.53% of the SO_2 emission factor. Applying the Technology Impact Factor from the APH of 0.5, the final heat input-based H_2SO_4 emission factor is approximately 1.03×10^{-5} lb/MMBtu.

No control efficiency has been applied to the emissions of SO_2 and H_2SO_4 from NG combustion within C2.

3.2.2.4 CO Emission Factor

NG combustion using a retractable spud burner as a component inside of a larger existing coal burner produces a unique set of combustion dynamics which may not be adequately represented by EPA's "default" NG combustion CO emission factor found in AP-42 Section 1.4 Table 1.4-1 (84 lb MMscf). Rather, EKPC considers CO BACT limits proposed by other similar, existing EGU boilers that were originally designed to burn coal and were subsequently retrofit to add NG co-firing capability to provide the best basis for establishing a potential CO emission factor for the modified C2 boiler. Therefore, the CO BACT limit of 0.12 lb CO/MMBtu for a coal and NG co-fired EGU boiler is used in the PEI calculations.

3.2.2.5 Greenhouse Gas Emission Factors

Like coal combustion, EKPC used the default emission factors in the U.S. EPA's Greenhouse Gas Reporting Program (40 CFR 98, Subpart C, Tables C-1 and C-2 for NG) to estimate annual GHG emissions from 100% NG combustion, and CO_2e emissions were calculated by multiplying the mass of each of the GHG by its associated GWP.

3.2.3 Potential Emissions from Co-Firing Coal and Natural Gas

After deriving the coal and NG combustion emission factors as specified in the preceding subsections, EKPC has documented hourly potential emissions resulting from the modification to burn either 100% coal or 100% NG within the DEP7007 N Form provided in **Appendix C**. The final variable calculated prior to determining the hourly PTE of C2 is the hourly heat input post-project while firing 100% coal and 100% NG. EKPC calculated the required heat input at various levels of coal firing based on engineering estimates of the gross power output from the steam turbine associated with C2. The resulting total heat input capacity of the burner system in a 100% coal firing scenario is 2,364 MMBtu/hr, as modeled, and that for a 100% NG firing scenario is 2,433 MMBtu/hr.

The hourly PTE for C2 post-modification is documented in the DEP7007 N Form in **Appendix C** to support a determination of the worst-case emissions profile between the 100% coal firing and 100% NG firing scenarios.

3.3 Cooper Project Ancillary Equipment

There are several emissions units that are part of the Cooper Project which support the operation of the CTs and C2. Descriptions of the emissions calculations for the ancillary equipment are provided in the following subsections.

3.3.1 Auxiliary Boiler (EU20), Fuel Gas (Dewpoint) Heaters (EU17, EU23, EU24), and HVAC Heaters (EU29A/B)

Potential emissions from the Auxiliary Boiler, fuel gas (dewpoint) heaters, and new HVAC heaters are estimated based on EKPC's vendor requirements, pipeline NG specifications, and published AP-42 emissions factors. Annual potential emissions for the Auxiliary Boiler, fuel gas (dewpoint) heaters, and HVAC heaters are documented in Sections 5.4, 6.4, 7.4, 8.4, 12.4, and 13.4 of **Appendix B**.

3.3.2 Emergency Use Diesel-Fired Engines (EU21 and EU22)

The emergency diesel-fired engine for the planned emergency generator (EU21) and the emergency diesel-fired fire water pump engine (EU22) will meet the emissions requirements specified in Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). Emissions of regulated NSR pollutants from the engines are based on either 40 CFR Part 60, Subpart IIII emissions limits – which points to U.S. EPA Tier 2 emissions limits for the generator and NSPS IIII Table 4 for the fire pump engine – or AP-42 emissions factors for regulated NSR pollutants and HAPs.

Annual potential emissions based on these methodologies for the emergency generator are shown in Section 10.4 and annual potential emissions for the emergency fire water pump engine are shown in Section 11.4 in **Appendix B**. Consistent with past KDAQ permitting practice, the PTE from these emergency-use engines is based on 500 hours per year of operation.[14]

3.3.3 Cooling Tower (EU25)

The 9-cell cooling tower to be installed as part of the CCGT Project will be a source of PM emissions. As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. PM emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of PM.

The annual PTE of PM from the cooling tower has been estimated as a function of cooling water recirculation rate, drift loss, and TDS concentration in the recirculating water. The planned specifications for the new cooling tower require a cooling water recirculation rate of 165,800 gallons per minute (gpm), a drift loss rate through the mist eliminators of 0.0005%, and a TDS concentration of 2,500 ppm.

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[14] In a memo from EPA Air Quality and Planning Standards Director John S. Seitz to the regional directors of Air and Radiation, "Calculating Potential to Emit (PTE) for Emergency Generators", dated September 6, 1995, EPA formalized its position that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

Using these parameters, an aerodynamic particle size distribution was derived according to the methodologies presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie.[15] The linear interpolation calculations used to develop the particle size distribution are outlined in Section 9.3 of **Appendix B**. This methodology derives scaling factors equal to the percentage of particles less than a target aerodynamic particle diameter to be applied to the filterable PM emission factor developed based on the parameters specified above.

The emission factors for PM, PM_{10}, and $PM_{2.5}$ developed using the methodologies above are summarized in Section 9.3.2 of **Appendix B**, and the annual PTE of the new cooling tower is summarized in Section 9.4 of **Appendix B**.

3.3.4 Storage Tanks (EU26A/B, EU27, EU28, and EU34)

All fuel storage tanks are considered sources of VOC emissions, and EU34 is a source of H_2SO_4 emissions. Standing and working losses were calculated for all storage tanks using TankESP®, which calculates working and breathing losses using the most current version of AP-42 Section 7.1. – *Organic Liquid Storage Tanks*.[16] Annual potential VOC emissions from the two FO storage tanks serving the CTs are documented in Section 14.3 of **Appendix B**. Annual potential VOC emissions from the emergency generator engine and fire water pump engine belly tanks are documented in Sections 15.3 and 16.3, respectively.

In addition to the AP-42 Section 7.1 methodologies used by TankESP, stock properties for the 93% sulfuric acid solution have been calculated using interpolated partial pressure data from Perry's Chemical Engineer's Handbook (8th Edition) for the vapor species at the specified H_2SO_4 concentration. Annual potential H2SO4 emissions from the 93% sulfuric acid storage tank are documented Section 24.3.

3.3.5 Circuit Breakers (EU30 and EU31)

The circuit breakers may occasionally leak SF_6 to the atmosphere, where the pollutant acts as a greenhouse gas. Annual CO_2e emissions from the leaking of SF_6 from the circuit breakers have been calculated assuming a 0.5% leak rate per year[17] and a GWP of 23,500.

3.3.6 New Haul Roads (EU32)

Fugitive PM emissions potentially caused due to the increased vehicle traffic and altered roadways resulting from the need to deliver various chemicals and fuel to the CT buildings have been estimated using the methodologies of AP-42, Section 13.2.1 for Paved Roads. EKPC will use existing paved roadways throughout the plant and pave new roadways to accommodate the increased vehicle traffic. EKPC anticipates truck traffic for the delivery of the following:

- ULSFO;
- Aqueous ammonia; and
- Chemicals for Water Treatment and the Cooling Tower.

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[15] "Calculating Realistic PM_{10} Emissions from Cooling Towers," Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

[16] https://www.trinityconsultants.com/software/tanks/tankesp

[17] 0.5% leak rate is BACT.

Each of the deliveries corresponds to a discrete truck route. The average truck weight per truck route was calculated based on the expected usage of each chemical, truck refill capacity, and an assumed empty truck weight of 16 tons. The total VMT per delivery truck route were measured based on conceptual drawings of the final paved roads post-project. The VMT-weighted average truck weight and total VMTs per truck route are summarized in Section 17.3 of **Appendix B**.

The PM, PM_{10}, and $PM_{2.5}$ emission factors were developed based upon Equation 1 in AP-42, Section 13.2.1:

$$E = k(sL)^{0.91}(W)^{1.02}$$

E = emission factor (lb/VMT)
k = particle size multiplier
sL = road surface silt content (g/m^2)
W = average vehicle weight (tons)

After deriving the emission factors for each of the four truck routes, an annual PTE was calculated by multiplying the emission factors by the calculated annual VMTs per delivery truck type. This emissions calculation methodology is further detailed in Section 17 of **Appendix B**.

3.3.7 Natural Gas Piping Fugitives

Section 18 of **Appendix B** details the emission calculation methodology used to estimate the annual PTE of VOC and CO_2e from leaks in the new NG piping components to be installed as part of both the CCGT Project and the C2 modification to implement NG combustion capabilities. The new piping components to be installed include the following:

- CCGT Project
  - 200 valves
  - 16 relief valves
  - 280 flanges
  - 2 sampling connections

- C2 Co-fire Project
  - 470 valves
  - 5 relief valves
  - 1,700 flanges

EKPC used emission factors published in EPA's "Protocol for Equipment Leak Emissions Estimates"[18] to calculate the annual VOC and CO_2e PTE from each type of component. The emission factors chosen are representative of oil and gas production operations and as such are appropriate to use for estimating NG fugitive emissions. The emission factors for valves and flanges in gas service from Table 2-4 in EPA's Protocol were used for all valves and flanges to be installed. For the sampling connections and relief valves, EKPC used the emission factors for "Other" components in gas service. Per footnote c to Table 2-4 in EPA's Protocol, the "Other" equipment type was derived from "compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents." As such, it is appropriate to apply the emission factor for the "Other" category to the sampling connections and relief valves.

[18] Protocol for Equipment Leak Emissions Estimates (Document EPA-453/R-95/017, November 1995)

The emission factors are representative of the total mass of leaking NG per hour per component (i.e., kg/hr/component). This emission factor can be applied to the emissions of either VOC or CO_2e by multiplying by an appropriate weight fraction. For pipeline-quality NG, EKPC has estimated that the NG stream transmitted to the plant will contain approximately 85.1% by weight methane, 0.43% by weight CO_2, and 1.10% by weight VOC. Applying these weight fractions to the emission factors from EPA's Protocol, a set of VOC, CO_2, and methane emission factors were developed for each component type. Multiplying by the number of components and assuming 8,760 hr/yr of operation, the annual PTE of VOC and CO_2e was calculated as shown in Section 18.4 of **Appendix B**.

3.4 Cooper Station Unmodified Sources

As documented in Section N.1 of the DEP7007 N form provided in **Appendix C**, EKPC is proposing various refinements to $PM/PM_{10}/PM_{2.5}$ potential emission rates for unmodified Cooper Station sources included in the PSD Air Quality Analysis. Specific changes made to the existing $PM/PM_{10}/PM_{2.5}$ potential emission calculation infrastructure for these unmodified sources are described in the following subsections.

3.4.1 Coal Handling Operations (EU03)

The Maximum Annual Capacity for Coal Handling Operations has been updated to coincide with the newly proposed Unit 1 and 2 combined coal annual operating limit (463,566 tpy) established in support of the $PM_{2.5}$ NAAQS modeling analysis. This annual coal throughput restriction is carried through directly to the Receiving Hopper No. 1, Crusher (Primary), Conveyor & Transfer (5), Reclaim Hopper, Stockpile, and Drop Point into Bunkers (KyEIS Process IDs 1-6). In addition, the PM_{10} and $PM_{2.5}$ emission factors have been updated to reflect the applicable particle size ratio data from AP-42 Chapter 13.2.4 for Aggregate Handling and Storage Piles for the coal hoppers, crushers, conveyors and transfer points.

For the Coal Stockpile (KyEIS Process ID 5), the $PM/PM_{10}/PM_{2.5}$ emission factors were updated based on applicable equations from EPA's reference document entitled *Control of Open Fugitive Dust Sources*.[19] Fugitive PM emissions can result from wind erosion when gusts of wind cause loose material on the surface of a pile to become airborne. The annual quantity of emissions is assumed to be dependent on the silt content of the material stored, the moisture of the pile (predicted by the number of days per year with measurable precipitation), and the percentage of hours per year that the wind speed exceeds a threshold speed of 12 miles per hour. Using site-specific estimates for these input parameters, updated $PM/PM_{10}/PM_{2.5}$ emission factors were first calculated on a pounds per day per acre basis using the method from *Control of Open Fugitive Dust Sources* and were further converted into a coal throughput normalized emission factor using the same maximum hourly and annual coal throughput rates applied to the other coal handling operations.

The potential $PM/PM_{10}/PM_{2.5}$ emissions basis for the Unpaved Yard Area (KyEIS Process ID 9) has been updated to reflect the maximum annual VMT associated with the annual coal throughput restriction and to include more representative emission factors from AP-42 13.2.2 for Unpaved Roads. In deriving the basis for the annual VMT, over the road haul trucks delivering coal at the maximum hourly and annual throughput were assumed to enter the unpaved yard area at the eastern access point, traverse a U-shaped route, and enter back onto the main plant, paved access road at the western access point. Similarly, front-end loaders were conservatively assumed to handle all coal unloaded from delivery trucks and move the coal from the coal dump location to the furthest point on the perimeter of the coal stockpile and return empty to pick up

[19] *Control of Open Fugitive Dust Sources*; EPA-450/3-88-008, September 1988, Page 4-17, Equation 2, nepis.epa.gov/Exe/ZyPDF.cgi/91010T54.PDF?Dockey=91010T54.PDF

another load for dumping onto the stockpile. Based on this VMT calculation methodology, the maximum truck/loader travel distance has been assigned to each coal load in a manner that maximizes the resulting VMT associated with coal deliveries and feeding to the Unit 1 and 2 coal bunkers. Updated $PM/PM_{10}/PM_{2.5}$ emission factors were derived from Equation 1a of AP-42 Chapter 13.2.2 using the applicable particle size multipliers and empirical constants, a representative surface material silt content for Plant Roads at Western Surface Coal Mining operations from Table 13.2.2-1, average vehicle weights for applicable truck/front-end loader types, and precipitation data from the London, KY National Weather Service (NWS) station. The resulting lb/VMT emission factors for $PM/PM_{10}/PM_{2.5}$ were used with the maximum hourly and annual VMT estimates to determine the hourly and annual potential $PM/PM_{10}/PM_{2.5}$ emission rates for the unpaved yard area.

3.4.2 Coal Crushing Facility (EU07)

Following a similar approach to the Coal Handling Operations, the annual coal throughput and $PM_{10}/PM_{2.5}$ particle size ratios for the Coal Crushing Facility [including the Reclaim Hopper, Crusher (Secondary), and Conveyor & Transfer (4) in KyEIS Process IDs 1-3] were updated to reflect the newly proposed operating limit and applicable particle size data from AP-42 Chapter 13.2.4 for Aggregate Handling and Storage Piles.

3.4.3 Emergency Diesel Generator (EU08)

The $PM/PM_{10}/PM_{2.5}$ emission factors for the existing Emergency Diesel Generator (EU08) were updated to match the applicable values from AP-42 Chapter 3.4 for Large Stationary Diesel and All Stationary Dual-fuel Engines in place of the previously referenced emission factors from AP-42 Chapter 3.3 for Gasoline and Diesel Industrial Engines. The CAT 3516 Emergency Diesel Generator has a maximum horsepower rating of approximately 2,600 hp which significantly exceeds the large stationary diesel engine horsepower rating thresholds (600 hp) where AP-42 Chapter 3.4 would be applicable. Therefore, EKPC has appropriately updated the EU08 $PM/PM_{10}/PM_{2.5}$ emission factors to match the most representative data from AP-42.

3.4.4 Pebble Lime, Fly Ash, and Waste Product Handling System (EU09)

The annual material throughput rates for lime, fly ash, and waste product handling system equipment covered by EU09 (KyEIS Equipment IDs EQPT005 and EQPT006-010) is proportional to the coal throughput for Units 1 and 2. Therefore, a scaling factor (0.38) was applied to the maximum annual throughput for these EU09 sources based on the ratio of the newly proposed annual coal throughput limitation (463,566 tpy) to the post-project unconstrained/unlimited annual coal throughput rate for Units 1 and 2 (1,229,225 tpy based on the maximum hourly coal throughput rates of Units 1 and 2 of 93.37 ton/hr and 46.96 ton/hr, respectively, assuming continuous annual operation of 8,760 hr/yr). Finally, the $PM_{2.5}$ particle size ratio for these EU09 material handling sources was updated based on AP-42 Appendix B Generalized Particle Size Distributions Table B.2-2 Description of Particle Size Categories for the most representative Category 5 reflecting the "Process: Calcining and Other Heat Reaction Processes" and covering the "Material: Aggregate, Unprocessed Ore." The selected AP-42 Appendix B generalized particle size distribution for aggregates and unprocessed ores manufactured in calcining and other hot reaction processes is expected to provide an adequately representative particle size distribution for the types of pebble lime, fly ash, and waste product material handling activities covered by EU09 because these Cooper Station raw materials and byproducts are themselves generated in hot processes in a manner that produces similar aggregate materials to the underlining technical basis of AP-42 Table B.2-2 Category 5.

3.4.5 Paved Roadways (EU10)

The existing Paved Roadway designation in the Cooper Station Title V permit predominantly addresses coal deliveries as the basis for the maximum hourly and annual VMT as all other raw material deliveries and byproduct/waste product shipments have a much lower throughput and associated contribution to paved road vehicle traffic. For this reason, EKPC updated the Paved Roadway (EU10) hourly and annual VMT to reflect the newly proposed annual coal throughput restriction. Coal delivery trucks were assumed to traverse the full distance from the plant entrance to the coal stockpile/unpaved yard area access point and to return empty via the same basic route as these trucks entered the Cooper Station. A nominal coal delivery truck capacity of 40 tons was used to determine the number of trips required to achieve the proposed annual coal throughput restriction. Updated PM/PM_{10}/$PM_{2.5}$ emission factors were determined using Equation 1 from AP-42 Chapter 13.2.1 with applicable particle size multipliers, a representative road surface silt loading for ubiquitous baseline at an average daily traffic (ADT) of <500 from Table 13.2.1-1, average vehicle weights from representative coal delivery truck specifications, and precipitation data from the London NWS station.

4. NSR APPLICABILITY ASSESSMENT

This section addresses the methodology used to quantify the emissions increase from the proposed Cooper Project and assesses applicability of the NSR permitting regulations.

4.1 PSD/Nonattainment NSR Applicability Background

The NSR program was designed to protect public health and welfare from the effects of air pollution and to preserve and/or improve air quality throughout the nation. The NSR program requires certain stationary sources of air pollution to obtain air pollution permits prior to beginning construction. Construction of new sources with emissions above statutory thresholds, and modifications of existing sources emitting above those thresholds or that increase emissions of regulated NSR pollutants by more than the major modification thresholds specified in the NSR regulations are subject to NSR permitting requirements.

The major source NSR regulations encompass two distinct programs that each have unique requirements for new or modified sources. The applicability of these two programs depends on the area's attainment status with respect to the NAAQS. The PSD program, based on requirements in Part C of Title I of the Clean Air Act (CAA), applies to pollutants for which the area is not exceeding the NAAQS (areas designated as attainment or unclassifiable) and to regulated NSR pollutants for which there are no NAAQS. The nonattainment NSR (NNSR) program, based on Part D of Title I of the CAA, applies to pollutants for which the area is not meeting the NAAQS (areas designated as nonattainment).

Cooper Station is located in Pulaski County, Kentucky, which has been designated by the U.S. EPA as an unclassified/attainment area for all criteria pollutants.[20] As such, only PSD permitting requirements are potentially applicable to the proposed project

4.2 PSD Program Source Classification

Kentucky has incorporated the requirements of the PSD permitting program into its SIP at 401 KAR 51:017.[21]

The PSD requirements apply to the construction of a new *major stationary source* (as defined in 401 KAR 51:001, Section 1(118)) **<u>or</u>** any 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) that is a major modification.

A stationary source is a major source if the PTE for a specific pollutant equals or exceeds the major source threshold for *regulated NSR pollutants*.[22] The regulated NSR pollutants of relevance for the types of emission units covered by the proposed project are NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, lead, and H_2SO_4 mists.

For projects involving increases in GHG emissions, the mechanism for triggering PSD review is different from other regulated NSR pollutants. For a project to trigger PSD review for GHG, GHG must first become *subject*

[20] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-81/subpart-C/section-81.318 and https://www3.epa.gov/airquality/greenbook/anayo_ky.html

[21] 40 CFR 51.166(a)(1)

[22] *Regulated NSR Pollutant* defined in 401 KAR 51:001, Section 1(207)

to regulation to be treated as a regulated NSR pollutant that can fall under the PSD requirements.[23] A physical change or change in the method of operation at a facility that results in an emissions increase of a non-GHG pollutant exceeding the significance thresholds **and** an emissions increase of GHG exceeding 75,000 tpy CO_2e (for the project alone and on a net basis considering contemporaneous emissions increases and decreases) would make the GHG emissions increase from the project subject to regulation and would require PSD review for the GHG emissions from the new units associated with the proposed project.[24]

The threshold for defining a facility as a major stationary source under the PSD permitting program is 250 tpy of any regulated NSR pollutant unless the facility belongs to one of 28 specially named source categories (List of 28), in which case the major stationary source threshold is 100 tpy.[25,26] Existing operations at Cooper Station, classified under SIC Code 4911, "Electric Services", include "fossil fuel-fired steam electric plants," which is a named category on the List of 28. As such, the major source threshold for the PSD program is 100 tpy. The potential emissions of at least one regulated NSR pollutant currently exceeds 100 tpy; therefore, Cooper Station is classified as an existing major stationary source under the PSD program.

4.3 PSD Applicability Analysis Methodology

4.3.1 Defining the Project

The proposed CCGT EGU Project involves the installation and operation of the new CCGT system and the addition of ancillary sources in support of these operations.

The proposed C2 Co-Firing Project involves the addition of NG firing in an existing emissions unit, C2 Boiler, that is retaining its pre-project coal-firing capability to generate steam/electricity.

This permit application addresses both of these projects together, although they can be legally separated. This approach as a single project (the Cooper Project) streamlines the permitting process. EKPC reserves the right to provide justification for these activities as separate projects in the future if circumstances associated with the application review and processing necessitate a separation of the projects.

4.3.2 Existing versus New Emission Units

For purposes of calculating project-related emissions increases (labeled herein as project emissions increase or PEI), different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the combined project is considered a new or existing emission unit.

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[23] *Subject to regulation* is defined in 401 KAR 51:001, Section 1(231), which cross-references the federal definition in 40 CFR 51.166(b)(48).

[24] The component of the "subject to regulation" definition relating to the 100,000 tpy CO_2e major source threshold was recently revoked by the U.S. Supreme Court in Utility Air Regulatory Group (UARG) v. Environmental Protection Agency (EPA) (No. 12-1146) ruling.

[25] 401 KAR 51:001, Section 1(118)

[26] Being a List of 28 source says nothing about whether a facility is classified as a minor or major source under PSD or whether it is subject to PSD permitting requirements. Being on the List of 28 imparts no particular regulatory requirements or permitting obligations. It only defines what the major source threshold is for a facility in an attainment area.

401 KAR 51:001, Section 1(64) defines *emission units* as any part of a stationary source that emits or would have the PTE any regulated NSR pollutant. For purposes of this section, there are two types of emissions units:

> *(a) A **new emissions unit** is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> *(b) An **existing emissions unit** is any emissions unit that does not meet the requirements in paragraph (a) of this subsection or is a replacement unit.*

The proposed CTs, auxiliary boiler, emergency generator, fire pump engine, dew point heaters, HVAC heaters, cooling tower, storage tanks, circuit breakers, NG piping components, and increased plant paved-road traffic meet the definition of new emissions units.

The C2 boiler, which will be converted to a NG/coal co-fired boiler, and the associated upstream coal handling equipment meet the definition of an existing emissions unit.

4.3.3 Two-Step Major Modification Determination Process

As Cooper Station is classified as an existing major stationary source for PSD, if the proposed project meets the definition of a *major modification* (specific to each regulated NSR pollutant), then the full PSD permitting requirements apply for that pollutant. *Major modification* is defined at 401 KAR 51:001, Section 1(114):

> *"Major Modification"* means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase [Step 1] and a significant net emissions increase of a regulated NSR pollutant [Step 2] … [Step 1 & Step 2 added]

Certain exemptions to the major modification definition exist that, if applicable, means a project does not require an emission increase assessment. The Cooper Project does not qualify for any of the established exemptions.

Pursuant to 401 KAR 51:001, Section 1(219), *significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is *significant* (as defined in 401 KAR 51:001, Section 1(218)) for that pollutant. For those pollutants with *significant emission increases*, the net creditable emission increases and decreases over the contemporaneous period (as defined in 401 KAR 51:001, Section 1(144)(c)) are estimated and the *net emissions increase* is calculated for comparison with the *significant* thresholds (as defined in 401 KAR 51:001, Section 1(218)).

Net emissions increase (NEI) is defined by 401 KAR 51:001, Section 1(144) as:

> *"Net Emissions Increase"* means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:

(i) *The increase in emissions … as calculated pursuant to* 401 KAR 51:017, Section 1(4). [for existing units, calculated by actual-to-projected actual [27] or actual-to-potential; for new units, calculated by actual-to-potential] [28, 29]

(ii) *A*ny other increases and decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…

Step 1 is commonly referred to as the "project emission increases (PEI)" analysis as it accounts only for emissions related to the proposed project itself. If the emission increases estimated per Step 1 exceed the major modification thresholds, then the applicant may move to Step 2, commonly referred to as the 5-year netting analysis. The netting analysis includes all projects in the contemporaneous period for which creditable emission increases or decreases occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting requirements apply.

4.4 Components of Project Emission Increases

To calculate the PEI, the difference between a future emission level (either potential emissions or projected-actual-emissions) and the BAE must each be calculated. These components of the emission increase calculation formula are defined in the following sections.

4.4.1 Potential Emissions

For new emission units, future emissions are based on the future annual potential emission rate of the unit considering inherent physical and operational constraints on the production capacity of the equipment and federally enforceable emissions/operating limitations, where applicable.

4.4.2 Baseline Actual Emissions (BAE)

For existing emission units being modified or affected, to calculate the emission increases associated with the proposed project, BAE are first determined. *Baseline Actual Emissions* are defined by 401 KAR 51:001, Section 1(20):

> *For an existing electric utility steam generating unit (EUSGU),* baseline actual emissions means the average rate, in tons per year, the unit actually emitted during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date the owner or operator begins actual

[27] 401 KAR 51:017, Section 1(4)(a)1., Actual-to-projected-actual applicability test for projects that only involve existing emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[28] 401 KAR 51:017, Section 1(4)(a)2., Actual-to-potential test for projects that only involve construction of new emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[29] 401 KAR 51:017, Section 1(4)(a)3., *Hybrid test for projects that involve multiple types of emission units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods specified in subparagraphs 1 and 2 of this paragraph as applicable … equals or exceeds the significant amount for that pollutant …*

> construction of the project, unless a different 24-month time period is more representative of normal source operation…

For new emission units covered in the project scope, the BAE are set to zero.

The baseline period for existing units can be selected on a pollutant-by-pollutant basis, but for a given pollutant, only one baseline period can be used across all new, modified, and associated emission units in the project scope. The baseline period selection process typically involves a review of historical production and emissions data over the previous 5 years at an existing electric utility steam generating unit (EUSGU) to identify a historically representative period of 24-month rolling average production/annual emissions.

The presumed start of on-site construction is January 1, 2027 for the Cooper Projects. The 5-year period immediately preceding this date begins on January 1, 2022. Thus, for the Cooper Project the earliest baseline period available to select for each pollutant is the 24-month period ending December 2023 (i.e., January 2022 to December 2023).

The selected baseline period for each pollutant used along with documentation of the BAE are provided in Section 22 of **Appendix B** for the C2 boiler.

4.4.3 Projected Actual Emissions (PAE)

Projected Actual Emissions (PAE) are defined by 401 KAR 51:001, Section 1(199):

> *"Projected actual emissions" means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.*

In determining PAE, following 401 KAR 51:001, Section 1(199)(b)1.a., the source:

> *Considers all relevant information, including historical operational data and the company's own representations of expected and highest projected business activity, filings with the cabinet and the U.S. EPA, and compliance plans under the Kentucky SIP...*

Alternatively, per 401 KAR 51:001, Section 1(199)(b)2, the source may also elect to utilize the PTE in lieu of projected actual emissions:

> *Elects to use the emissions unit's potential to emit, in tons per year, instead of using subparagraph 1. of this paragraph to determine projected actual emissions.*

To allow for maximum post-project fuel flexibility to meet the electricity generation demands of EKPC members, EKPC has elected to utilize the PTE approach outlined in 401 KAR 51:001, Section 1(199)(b)2 in lieu of PAE. Due to significant uncertainty with respect to applicable regulatory requirements for coal-fired EGUs post-project, as well as fluctuations in fuel supply and pricing, EKPC cannot readily predict whether the post-project heat input will be achieved utilizing NG or a mixture of NG and coal in a co-firing scenario. The post-project scenarios are described as follows:

- Scenario 1: PTE when co-firing NG with coal, considering a synthetic minor SO_2 emission limit for the Cooper Project.
- Scenario 2: PTE when firing 100% NG.

In Scenario 1, the coal heat input is assumed to be equivalent to the total C2 boiler heat input (coal plus FO) during the baseline period, and the NG heat input is set to the level needed for the Step 1 increase to remain below a synthetic minor SO_2 emission limit.

The potential emissions utilized in the emission increase calculations were determined as the worst-case annual emission rate of the two scenarios on a pollutant-by-pollutant basis. Note that the potential emissions do not specifically include FO firing, which is used during startup of C2 on coal, as the emissions from the two scenarios adequately account for any emissions from the FO used in relatively small amounts as a percentage of the C2 boiler's heat input.

4.5 Project Emission Increase Evaluation

As stated above, the proposed project will constitute a modification to an existing major stationary source and involves new emissions units and existing emissions units. The procedure for calculating whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified. Pursuant to 401 KAR 51:017, Section 1(4)(a)3,

> *(3)* **Hybrid test for projects that involve multiple types of emissions units.** A significant emissions increase of a regulated NSR pollutant shall be projected to occur if the sum of the emissions increases for each emissions unit, using a method specified in subparagraphs 1 and 2 of this paragraph as applicable for each emissions unit, equals or exceeds the significant amount for that pollutant.

Subparagraph (1) of 401 KAR 51:017, Section 1(4)(a) references the **actual-to-projected-actual applicability test** for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the PAE and the BAE for each existing emissions unit, equals or exceeds the significant amount for that pollutant.

Subparagraph (2) of 401 KAR 51:017, Section 1(4)(a) references the **actual-to-potential test** for projects that only involve construction of a new emissions unit(s).

Therefore, for hybrid projects that involve existing and new emission units, such is the case with the proposed project, an actual-to-projected actual applicability test is used for the existing units and an actual-to-potential test is used for the new units. The sum of emission increases from these tests for all affected units associated with the project is the total PEI assessed against the significance thresholds in Step 1.

PEI = Sum of New EUs (PTE) + Sum of differences of Existing EUs (PAE – BAE)

4.5.1 Emission Increases for New Emission Units

For newly constructed emission units, annual emission increases are calculated as the "sum of the PTE from each new emissions unit following completion of the project."[30] Fugitive emissions are included in the annual emissions total for the PSD applicability determination since the facility is included in a source category specifically defined in 401 KAR 51:017 Section 7(1)(c).

For the PSD permitting program, "potential to emit (PTE)" is defined as the "maximum capacity of a stationary source to emit a pollutant under its physical or operational design."[31] Based on these considerations, annual potential emissions are calculated for each new emission unit based on representative emission factors for each unit type and used in the PSD applicability analysis.

4.5.2 Emission Increases for Modified Emission Units

As previously discussed, the C2 boiler will be physically modified as a part of the project to allow for firing of NG, or co-firing NG with coal. Pursuant to 401 KAR 51:017, Section 1(4)(a)(1), the Step 1 emissions increase for a modified existing emission unit is normally calculated as the difference between the projected actual emissions and the BAE. However, the applicant has the flexibility to rely on the more conservative actual-to-potential test for modified existing units in any situation where such a change is deemed appropriate.

For the actual-to-projected actual test, the initial emission increase is calculated by subtracting the BAE from the PAE (which is set to PTE as described in Section 4.4.3). The evaluation against the PSD triggering thresholds is calculated according to the following formula:

Project Emissions Increase (PEI) (tpy) = (PAE – BAE)

4.5.3 Emission Increases for Unmodified Emission Units

The only unmodified emission units potentially impacted by the project are those associated with coal handling. Since the C2 boiler will continue to fire coal post-project and the coal throughput projection is greater than the baseline coal throughput due to the Scenario 1 assumption that coal projected actual emissions are equivalent to the entire baseline heat input (coal plus FO), coal handling emissions must be calculated as the difference between the BAE and PAE for these emission units.

4.6 Contemporaneous Netting Analysis

PSD regulations allow the calculation of creditable emission increases and decreases over a contemporaneous period for each pollutant for which a significant emissions increase will occur as a result of the project. There were no projects within the 5-year contemporaneous period at the Cooper Plant which resulted in an emissions increase of any NSR-regulated air pollutants.

4.7 PSD Applicability Summary

For each relevant regulated NSR pollutant, **Table 4-1** lists the PSD SER for comparison against the PEI from Step 1 of the PSD applicability analysis.

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[30] 401 KAR 51:017, Section 1(4)(a)(3)

[31] 401 KAR 51:001, Section 1(190)(b)

Table 4-1. Cooper Project Emissions Increases Compared with PSD Significant Emission Rates

Pollutant	CCGT Project PTE[a] (tpy)	C2 Co-Firing Project Increase (tpy)	"Step 1" Project Emissions Increase (tpy)	PSD Significant Emission Rate[b] (tpy)	Project Triggers PSD Review? (Yes/No)
PM	171	11.0	**182**	25	Yes
PM_{10}	168	14.9	**183**	15	Yes
$PM_{2.5}$	167	14.7	**182**	10	Yes
NO_X	359	758	**1,119**	40	Yes
CO	4,805	1,238	**6,048**	100	Yes
VOC	456	52.6	**510**	40	Yes
SO_2	33.3	5.65	39.0	40	No
H_2SO_4	49.8	10.1	**59.9**	7	Yes
Lead	0.040	0.0025	0.043	0.6	No
GHG (as CO_2e)	2,943,501	816,284	**3,766,715**	75,000 [c]	Yes

a. The emissions from the increased haul road traffic and natural gas piping leaks that are associated with both the CCGT Project and the C2 Co-firing Project are included under the CCGT Project only.
b. 401 KAR 51:001, Section 1(218)(a) and (231).
c. For a project that causes a 75,000 tpy increase in CO_2e emissions and an increase above the SER for a non-GHG pollutant, GHG become subject to regulation and are treated as a regulated NSR pollutant with a PSD SER of 0 tpy.

Table 4-2 provides a summary of the C2 co-firing project increase provided in **Table 4-1**.

Table 4-2. Cooper C2 Co-Firing Project Increase

Pollutant	C2 BAE (tpy)	C2 PAE (tpy)	C2 Project Emissions Increase (tpy)
PM	8.85	19.85	11.0
PM_{10}	50.0	64.9	14.9
$PM_{2.5}$	46.5	61.2	14.7
NO_X	94.7	853	758
CO	40.5	1,279	1,238
VOC	4.8	57.5	52.6
SO_2	74.7	80.4	5.65
H_2SO_4	0.45	10.6	10.1
Lead	0.003	0.005	0.0025
GHG (as CO_2e)	431,631	1,247,915	816,284

A detailed table documenting the potential emissions from new emission units and the emission increases from modified emission units is provided in Section 2 of **Appendix B**.

To maintain post-project fuel flexibility, EKPC is pursuing a synthetic minor permitting strategy for SO_2. EKPC is proposing a combined SO_2 emission limit for the Unit 3 Gas Turbine, Unit 4 Gas Turbine, and C2 Boiler of 112.83 tpy, which is calculated as follows:

$$\text{Emission limit (tpy)} = \sum \text{BAE (tpy)} + 39\ \text{tpy} - \sum \text{PTE of Small Units (tpy)}$$

$$\text{Emission limit (tpy)} = 74.71\ \text{tpy} + 39\ \text{tpy} - 0.879\ \text{tpy}$$

$$\text{Emission limit (tpy)} = 112.83\ \text{tpy}$$

This equation calculates the maximum allowable emissions for the turbines and C2 boiler by summing up the BAE for units associated with the project, adding the PSD SER, and reducing this quantity by the PTE of low-emitting new emissions units associated with the project. This approach allows EKPC to demonstrate compliance with a synthetic minor limit through direct measurement of turbine and C2 boiler emissions, without a need to monitor emissions from the low emitting SO_2 emission sources associated with the project.

The Step 1 project emissions increase for lead and SO_2 will be less than their respective SERs. The Step 1 PEI for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 mists, and GHG exceed the SERs. Since there are no contemporaneous netting credits associated with these pollutants, PSD review under Sections 8 to 16 of 401 KAR 51:017 is required.

5. APPLICABLE FEDERAL AND STATE REQUIREMENTS

Emission units constructed as part of the proposed Cooper Project will be subject to certain federal and Kentucky air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to emission units constructed or modified as part of these projects. Specifically, applicability to NSPS, pollutant- and category-specific NESHAP, Compliance Assurance Monitoring (CAM), Title V operating permit regulations, Acid Rain Program (ARP), Cross-State Air Pollution Rule (CSAPR), and Kentucky SIP-specific regulations are addressed.

In **Appendix C**, the DEP7007 V Form identifies regulatory requirements for emission units cited below.

5.1 New Source Performance Standards

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA to establish federal emissions standards for source categories that cause or contribute significantly to air pollution. EPA is required to establish standards based on the best systems of emission reductions from technologies that have been adequately demonstrated, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except as noted. A review of all NSPS that could potentially be applicable to any of the new emission units associated with the project is presented in this section. The list of category-specific NSPS that will apply to the affected emission units are as follows:

- 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units – Applies to the Auxiliary Boiler (EU20) and Fuel Gas (Dewpoint) Heater No. 1 (EU17)
- 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines – Applies to CTs (EU18 and EU19)
- 40 CFR 60 Subpart TTTTa – Standards of Performance for GHG Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units – Applies to CTs
- 40 CFR 60 Subpart IIII – Stationary Compression Ignition Combustion Engines – Applies to the 1.25 MW Diesel Emergency Generator Engine (EU21) and the Fire Pump Engine (EU22)

5.1.1 NSPS Subpart A – General Provisions (Applicable)

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods (RMs), and mandates general control device requirements for all other subparts as applicable.

5.1.2 NSPS Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators* (NSPS D), applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971.[32] The rule defines a fossil fuel-fired steam generating unit as:[33]

> *A furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.*

The CTs (EU18 and EU19) will not be subject to NSPS D because the CTs are not classified as steam generating units under this regulation.

Upon implementation of co-firing capabilities, C2 is potentially subject to NSPS Subpart D as it meets the definition of a fossil-fuel fired steam generating unit. However, the potential applicability of the superseding NSPS Subpart Da, as discussed in Section 5.1.3 below, dictates that NSPS Subpart D would not apply.

The Auxiliary Boiler (EU20), three Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24), and individual HVAC heaters (EU29) are each not subject since their heat input capacities are each less than 250 MMBtu/hr.

5.1.3 NSPS Subpart Da – Electric Utility Steam Generating Units > 250 MMBtu/hr (Not Applicable)

40 CFR *Subpart Da – Standards of Performance for Electric Utility Steam Generating Units* (NSPS Da), provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.[34] The term "steam generating unit" is defined under this regulation as:[35]

> *For facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.*

While the CTs would be classified as fossil-fuel-fired steam generators associated with CCGTs, the CTs will not be subject to NSPS Subpart Da per 40 CFR §60.4305(b), which states that heat recovery steam generators regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart Da.

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[32] 40 CFR §60.40

[33] 40 CFR §60.41

[34] 40 CFR §60.40Da(a)

[35] 40 CFR §60.41Da

C2 is considered to be an *EUSGU* under NSPS Da because it individually burns fossil fuels at a rate greater than 250 MMBtu/hr and more than one third of its net electrical output is sold to the grid. Any existing EUSGUs for which *construction*, *modification*, or *reconstruction* is commenced after September 18, 1978, become subject to the applicable emission limitations and monitoring, recordkeeping, and reporting requirements in NSPS Subpart Da.

As C2 is an existing unit, this project is not considered *construction*.

An additional applicability determination can be made by assessing whether the proposed project is considered a *modification* of an existing EUSGU. Pursuant to 40 CFR §60.14(a), a *modification* is defined as any physical or operational change to an existing facility, which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies.

For evaluating emission rate increases under the NSPS *modification* definition, the emission rate must be expressed on a maximum hourly basis before and after the proposed project. The change to NG-firing in C2 must be evaluated as to whether a short-term emissions increase of a pollutant to which a standard applies (NO_X, SO_2, or filterable PM) occurs.

The change to co-firing in C2 will not result in a short-term emissions increase of a pollutant to which a standard (i.e., NSPS Subpart Da) applies, and the C2 Modification is not considered a *modification* under NSPS. It is well understood that short-term hourly emissions of SO_2 and filterable PM will significantly decrease when firing NG compared with coal. For NO_X emissions, EKPC expects that actual emissions from NG co-firing will be less than or equal to emissions from coal firing due to lower inlet loading of NO_X when firing natural gas and SCR NO_X removal.

5.1.4 NSPS Subpart Db – Steam Generating Units > 100 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* (NSPS Db), provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[36] The term "steam generating unit" is defined under this regulation as:[37]

> *Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.*

While the CTs would be classified as steam generators that combust fuel and are part of combined cycle systems, the CTs will not be subject to NSPS Subpart Db because they will be subject to the provisions of NSPS KKKK and as such will meet the exemption from this regulation under 40 CFR §60.40b(i).

Regarding C2, the potential applicability of the superseding NSPS Subpart Da, as discussed in Section 5.1.3 above, dictates that NSPS Subpart Db would not apply.

[36] 40 CFR §60.40b(a)

[37] 40 CFR §60.41b

The Auxiliary Boiler (EU20) and three Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24) are not subject to Subpart Db since their heat input capacities are each less than 100 MMBtu/hr.

5.1.5 NSPS Subpart Dc – Small Steam Generating Units (Applicable)

40 CFR 60 *Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* (NSPS Dc), provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989, and for which the maximum design heat input capacity is 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.[38] The term "steam generating unit" is defined under this regulation as:[39]

> *Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.*

Both the new NG-fired Auxiliary Boiler (EU20) and the Fuel Gas (Dewpoint) Heater serving C2 (EU17) meet the definition of a steam generating unit and fall within the applicable heat input capacity range. Therefore, each is an affected facility after the applicability date.[40] Units subject to NSPS Subpart Dc that fire NG do not have to meet any applicable emission limits, testing, or monitoring requirements under this subpart, except for the requirement to monitor NG consumption on a monthly basis. Initial notifications of the dates of construction commencement, anticipated startup, actual startup, in addition to the design heat input capacity and the identification of fuels to be combusted must be submitted to the Division.

The two Fuel Gas (Dewpoint) Heaters serving the two CTs (EU23 and EU24) and the individual HVAC heaters (EU29) are not subject to Subpart Dc since their heat input capacities are each less than 10 MMBtu/hr.

5.1.6 NSPS Subpart Kc – Volatile Organic Liquid Storage Vessels (Not Applicable)

40 CFR 60 Subpart Kc applies to each storage vessel with a capacity greater than or equal to 20,000 gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after October 4, 2023. NSPS Subpart Kc defines "storage vessel" and "volatile organic liquids" as follows:

> *Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include 1) frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors; 2) subsurface caverns or porous rock reservoirs; or 3) process tanks.*
>
> *Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.*

[38] 40 CFR §60.40c(a)

[39] 40 CFR §60.41c

[40] The Fuel Gas (Dewpoint) Heaters are equipped with a water/glycol bath (i.e., the heat transfer medium) that indirectly heats the pipeline gas stream, which makes these units subject to NSPS Dc.

Based on these definitions, the two FO Storage Tanks (EU26a and EU26b) serving the CTs meet the definition of "storage vessels" under NSPS Subpart Kc, and the FO to be stored in them is a potential source of VOCs. As such, the FO Storage Tanks meet the definition of VOL storage vessels. 40 CFR §60.110c(b) provides exemptions from NSPS Subpart Kc. One exemption – 40 CFR §60.110c(b)(8) – specifies that any vessels storing VOL with a maximum true vapor pressure less than 0.25 psia (1.7 kPa absolute) are not subject to NSPS Subpart Kc. EU26a and EU26b will only store ULSFO, which exhibits a true vapor pressure less than 0.01 psia, well below the applicability threshold.

The emergency engine belly tank (EU26) will have a capacity of 1,000 gallons. The fire water pump engine belly tank (EU27) will have a capacity of 350 gallons. Both storage vessels have capacities below the applicability threshold and are therefore not subject to NSPS Subpart Kc.

5.1.7 NSPS Subpart GG – Stationary Gas Turbines (Not Applicable)

40 CFR 60 *Subpart GG – Standards of Performance for Stationary Gas Turbines* (NSPS GG), applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the LHV of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[41]

The CTs (EU18 and EU19) will be stationary gas turbines with heat inputs above the threshold and constructed after the applicability date. However, pursuant to 40 CFR §60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG does not apply.

5.1.8 NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (Applicable)

40 CFR 60 *Subpart IIII - Standards of Performance for Stationary Compressions Ignition Internal Combustion Engines* (NSPS IIII) applies to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006 that are not fire pump engines, and fire pump engines manufactured after July 1, 2006 that commence construction after July 11, 2005.

5.1.8.1 Emergency Generator (EU21)

The CCGT Project is provisioned to have a 1.25 MW rated emergency generator and will be a 2021 model year or later unit. Since the emergency diesel fired engine (approximately 2,200 bhp) serving the generator will be used for emergency purposes and cylinder displacement is less than 10 liters/cylinder, the engine will be subject to the emission limits in 40 CFR §§60.4205(b) and 60.4202(a)(2) and the fuel specifications of 40 CFR §60.4207.

Per 40 CFR §60.4205(b),

> *(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.*

Per 40 CFR §60.4202(a)(2),

[41] 40 CFR §60.330

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

> *(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.*

Starting with Model Year 2006, a new engine with a rated power greater than or equal to 130 kW but less than or equal to 560 kW, must meet the Tier 3 standard in Table 3 to Appendix I as specified in 40 CFR Part 1039. As the emergency generator's rated power output will be greater than 560 kW, it must meet the Tier 2 standards in Table 2 to Appendix I.[42]

Table 2 to Appendix I - Tier 2 Emission Standards contain the following applicable emission limits for model year 2006 or later units with rated power outputs greater than 560 kW:

- 6.4 grams per kilowatt hour (g/kW-hr) (equivalent to 4.8 g/hp-hr) of NMHC+ NO_X,
- 3.5 g/kW-hr (equivalent to 2.6 g/hp-hr) of CO, and
- 0.20 g/kW-hr (equivalent to 0.15 g/hp-hr) of PM.

Additionally, pursuant to 40 CFR §1039.105(b)(1) through (3), smoke from the engine may not exceed the following standards.

1. 20 percent during acceleration mode;
2. 15 percent during lugging mode; and
3. 50 percent during peaks in either the acceleration or lugging mode.

As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, EKPC will purchase an emergency generator certified to the emission limits listed 40 CFR §60.4205(b) or more stringent, and will install and configure the engine according to the manufacturer's specifications. No performance testing is required.

EKPC will use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, EKPC will monitor hours of operation of the emergency generators using non-resettable hour meters and records per 40 CFR §60.4214(b) will be maintained. No other monitoring is required.

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[42] https://www.ecfr.gov/current/title-40/part-1039#Appendix-I-to-Part-1039

5.1.8.2 Emergency Fire Pump Engine (EU22)

The CCGT Project is provisioned to have a nominal 310 hp fire pump engine that will combust ULSFO. The date of manufacture for the emergency fire pump engine and date of construction will occur after the dates specified above; therefore, the emergency fire pump engine will be subject to the provisions of NSPS IIII.

Since the proposed emergency fire pump engine will have a power rating of 310 hp and a displacement of less than 30 liters per cylinder, the emergency fire pump engine must comply with the emission standards in Table 4 of NSPS IIII for all pollutants [§60.4205(c)]. Specifically, the emergency fire pump engine must meet the following emissions standards for non-methane HC (NMHC)+NO_X, CO, and PM:

- 3.0 grams per horsepower-hour (g/hp-hr) of NMHC+NO_X,
- 2.6 g/hp-hr for CO, and
- 0.15 g/hp-hr of PM.

As documented in the emissions calculations provided in Section 11 of **Appendix B**, the proposed emergency fire pump engine will meet these emissions limits.

As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, EKPC will purchase an emergency fire pump engine certified to the emission limits listed in Table 4 of NSPS IIII, and will install and configure the engine according to the manufacturer's specifications. No performance testing is required.

Effective October 1, 2010, only diesel fuel that meets the requirements set forth in 40 CFR §1090.305 may be used in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, EKPC will monitor the emergency fire pump engine hours of operation using a non-resettable hour meter and records per §60.4214(b) will be maintained. No other monitoring is required.

5.1.9 NSPS Subpart KKKK – Stationary Combustion Turbines (Applicable)

40 CFR 60 *Subpart KKKK – Standards of Performance for Stationary Combustion Turbines* (NSPS KKKK) establishes emissions limits for a combustion turbine and associated HRSG that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input from the CT at peak load equal to greater than 10.7 gigajoules (10 MMBtu/hr) based on the HHV of the fuel. Because the CTs are subject to NSPS KKKK, they are exempt from NSPS GG.

The affected facility under NSPS KKKK is a stationary CT, which is defined by 40 CFR §60.4420 as follows:

> *All equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine, any regenerative/ recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.*

The CTs (EU18 and EU19) will be stationary CTs with heat inputs above the threshold and constructed after the applicability date; thus, they will be subject to NSPS KKKK. NSPS KKKK specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_X and SO_2.

On December 13, 2024, EPA published a proposed rule to amend the requirements in the NSPS for these affected facilities, to be located in a new Subpart KKKKa. 89 Fed. Reg. 101306 (Dec. 13, 2024). Once these requirements are finalized, EU18 and EU19 will be subject to the revisions.

5.1.9.1 Emissions Limits

For a new CT firing NG with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/ MWh gross energy output.[43] For units greater than 30 MW, NSPS KKKK also includes a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh gross output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.[44] Compliance with the NO_X emission limit is determined on a 30-unit operating day rolling average basis.[45] The new CTs will also be capable of firing FO. For a new CT firing fuels other than NG with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 42 ppm at 15% O_2 or 1.3 lb/MWh gross energy output.[46]

SO_2 emissions into the atmosphere from CTs located in the continental U.S. are limited to 0.90 lb/MWh gross output [or 110 nanograms per Joule (ng/J)], **or** the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[47]

As documented in detail in Section 4 of **Appendix B**, EKPC's CTs will have NO_X and SO_2 emissions well below the NSPS KKKK emissions standards and will comply with the applicable monitoring, reporting, and performance test requirements of NSPS KKKK.

5.1.9.2 Monitoring and Testing Requirements

Pursuant to 40 CFR §60.4333(a), the CT, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction. Additional emissions limit-specific compliance demonstration requirements are detailed in the following subsections.

5.1.9.2.1 NO_X Compliance Demonstration Requirements

The CT will use either water or steam injection; therefore, the continuous compliance requirements at 40 CFR §60.4335 apply. Pursuant to 40 CFR §60.4335(b)(1), EKPC will install, calibrate, maintain, and operate a CEMS as described in 40 CFR §60.4335(b) and 60.4345. EKPC will certify according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[48] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the

[43] 40 CFR §60.4320(a) and Table 1

[44] Ibid.

[45] 40 CFR §60.4350(h), 40 CFR §60.4380(b)(1)

[46] Ibid.

[47] 40 CFR §60.4330(a)(1) or (a)(2), respectively

[48] 40 CFR 60.4335(a)

initial relative accuracy test audit (RATA) required pursuant to 40 CFR §60.4405 to the applicable NO_X emission limit under NSPS KKKK.[49]

5.1.9.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by the Division;[50] however, EKPC elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[51] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the NG is less than or equal to 20 gr/100 scf of sulfur, that the fuel sulfur content for the FO is less than 0.05 weight percent or less of sulfur, and that results in potential emissions not exceeding 0.060 lb/MMBtu; or
- By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

EKPC will meet the SO_2 emissions limitation specified by 40 CFR §60.4330(a)(2) of 0.060 lb SO_2/MMBtu by accepting the fuel sulfur limitation shown in 40 CFR §60.4365(a) of 20 gr/100 scf of sulfur or less for NG and 0.05 weight percent or less for FO.

Pursuant to 40 CFR §60.4365(a), the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifies that the total sulfur content for NG used at Cooper Station is less than 0.5 gr/100 scf – which is 40 times lower than the required 20 gr/100 scf – and that the total sulfur content for FO used at Cooper Station is 0.0015 weight percent of sulfur (i.e., ULSFO) – which is over 33 times lower than the required 0.05 weight percent.

5.1.10 Subpart TTTTa – Standards of Performance for GHG Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (Applicable)

40 CFR 60 *Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* (Subpart TTTTa) is applicable to a stationary CT that commences construction or reconstruction after May 23, 2023, and meets the following relevant applicability conditions in 40 CFR 60.5509a(a)(1) and (2):

- Has a base load rating greater than 250 MMBtu/hr of fossil fuel; and
- Serves a generator(s) capable of selling greater than 25 MW of electricity to a utility power distribution system.

[49] 40 CFR 60.4405(c)

[50] 40 CFR 60.4370(b) and (c)

[51] 40 CFR 60.4365

Given that the proposed CTs meet all three applicability criteria under 40 CFR §60.5509a(a) and do not meet any of the exemption criteria under 40 CFR §60.5509a(b), each CT would be subject to the provisions of Subpart TTTTa.

Multiple petitioners, however, are challenging the legality of Subpart TTTTa, in a lawsuit which is pending at the time of submittal of this Application. EKPC acknowledges the potential that Subpart TTTTa could be vacated by the Court in whole or in part or remanded to EPA for revisions prior to the issuance of the permit at issue. Although EKPC lists Subpart TTTTa as an applicable regulation, if Subpart TTTTa is no longer effective or is revised, the overall applicability of Subpart TTTTa and/or its regulatory requirements and timelines may change. If such a regulatory change occurs, EKPC would plan to revise this Application as necessary prior to issuance of the permit and would coordinate with the Division to conform this Application to the regulatory status of Subpart TTTTa and Subpart TTTT, its predecessor, if that regulation becomes applicable. EKPC is permitting Unit 3 and 4 at a 100% capacity factor, should Subpart TTTTa be vacated, repealed, or modified, such that a higher capacity factor is allowed. As provided below, the potential emissions in this Application are based on 8,760 hours of operation.

Subpart TTTTa provides a different CO_2 emission limit for base load CTs than the limit for an intermediate load CTs. In addition, the emission limit for a CT that uses both NG and FO as a fuel also varies.

If a stationary CT supplies greater than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis, then the stationary CT is a base load CT.

The potential emissions from each CT (EU18 and EU19) are based on 8,760 hours per year of operation, as a combination of steady-state operations on NG and FO, along with time for shutdowns, idle/non-operation, and cold/hot/warm startups. In one scenario, the worst-case PTE for each CT is based on 4,306 steady-state hours on NG, 1,080 steady-state hours on FO, and numerous SU/SD events. In the other scenario, the worst-case PTE also allows for burning NG up to 7,680 steady-state hours and 1,080 steady-state hours on FO. While not a direct correlation, these operational hours for calculating the PTE are well above 40% of its electrical output.

If one or both CTs are operated as base load CTs leading up to the compliance date for Subpart TTTTa, the CTs will be subject to the following key requirements under Subpart TTTTa:

- **Phase 1 Standard of Performance for Base Load CTs.** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages beginning before January 2032, emissions of CO_2 must be limited to 800 to 1,250 lb CO_2/MWh of gross energy output; **or** 820 to 1,280 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a.
- **Phase 2 Standard of Performance for Base Load CTs.** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages beginning after December 2031, emissions of CO_2 must be limited to 100 to 150 lb CO_2/MWh of gross energy output; **or** 97 to 139 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a.
- **Phases 1 and 2 Standard of Performance for Intermediate Load CTs (Capacity factor greater than 20% and less than 40%):** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages emissions of CO_2 must be limited to 1,170 to 1,560 lb CO_2/MWh of gross energy output; **or** 1,190 to 1,590 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a
- In addition, per 40 CFR §60.5525a(b), EKPC must operate and maintain each CT, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The

Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of your EGU.

The applicable requirements are shown in the DEP7007 V Form and in the attached permit markup.

It is important to note that the Cooper Unit 2 boiler is not subject to Subpart TTTTa in accordance with 40 CFR §60.5509a(b)(7) since the modification to add co-firing capability will not result in an hourly increase in CO_2 emissions of more than 10 percent.

5.1.11 Subpart UUUUa – GHG Emissions from Existing Electric Utility Generating Units (Not Applicable)

40 CFR 60 UUUUa was removed and reserved via 89 FR 40047, May 9, 2024.

5.1.12 Subpart UUUUb – Emission Guidelines for GHG Emissions for Electric Utility Generating Units (Not Applicable)

40 CFR 60 *Subpart UUUUb – Emission Guidelines for GHG Emissions for Electric Utility Generating Units* (Subpart UUUUb) provides guidelines for States to follow in developing, submitting, and implementing state plans to establish performance standards to reduce emissions of GHG from an affected steam generating unit. This final rule became effective on July 8, 2024.

Multiple petitioners are challenging the legality of Subpart UUUUb, in a lawsuit which is pending at the time of submittal of this Application. EKPC acknowledges the potential that Subpart UUUUb could be vacated by the Court in whole or in part or remanded to EPA for revisions prior to the issuance of the permit at issue. EKPC does not list Subpart UUUUb as an applicable regulation because it does not apply to individual units.

The Division is subject to a deadline to submit its Section 111 plan by May 9, 2026. That plan will contain requirements for applicable units. Subpart UUUUb contains design options to develop an approval state plan but does not impose any requirements directly on any sources within a state. Until EPA approves the state plan (forthcoming in 40 CFR Part 62), affected steam generating units will not be subject to federally enforceable requirements. Once Cooper Unit 2 is subject to federally enforceable requirements as part of the state plan, EKPC will update the permit as necessary to reflect the applicable requirements of Subpart UUUUb.

5.2 National Emissions Standards for Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for designated pollutants and source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of any individual HAP. Facilities with a total HAP PTE at an amount less than that of a major source are considered area sources. For major and some area HAP sources, allowable emissions limits are established (under 40 CFR 63) on the basis of a maximum achievable control technology (MACT) determination for the particular source type or category. The NESHAP under 40 CFR 63 apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

Cooper Station will remain a major source for individual HAP and total HAPs.

Any source subject to a NESHAP is also subject to the general provisions of 40 CFR Subpart A, except as noted. A review of all NESHAP that could potentially be applicable to any of the new emission units associated with the Cooper Project is presented in this section. The list of NESHAPs that will apply to the emission units for the project are as follows:

- 40 CFR 63 Subpart YYYY – NESHAP for Combustion Turbines – Applies to EU18 Unit 3 CT and EU19 Unit 4 CT
- 40 CFR 63 Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines – Applies to EU21 Diesel-Fired Generator/Engine and EU22 Diesel Pump/Engine
- 40 CFR 63 Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters – Applies to the Auxiliary Boiler (EU20) and Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24)
- 40 CFR 63 Subpart UUUUU – NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units – Applies to C2.

5.2.1 NESHAP Subpart EEEE – Organic Liquids Distribution (Non-Gasoline) (Not Applicable)

40 CFR 63 *Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution (Non-Gasoline)* (OLD MACT) applies to any non-gasoline organic liquids distribution (OLD) operation at major sources of HAP emissions. An OLD operation is defined as "the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed." Such activities include the storage of organic liquids.

OLD MACT also defines organic liquids under 40 CFR §63.2406. Paragraph (3)(i) under the definition for "organic liquid" specifically excludes diesel/No. 2 distillate oil from the definition of an organic liquid. As such, the two CT FO storage tanks (EU26A/B), emergency engine FO belly tank, and fire pump engine FO belly tank will not be affected facilities under OLD MACT.

5.2.2 NESHAP Subpart YYYY – Stationary Combustion Turbines (Applicable)

40 CFR 63 *Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* (NESHAP YYYY) establishes emissions and operating limitations for HAP from existing, reconstructed, or new stationary CTs, located at major stationary sources of HAP. EU18 Unit 3 CT and EU19 Unit 4 CT meet the definition of an affected source under NESHAP YYYY and therefore will be subject to this regulation.[52]

NESHAP YYYY requirements for each CT are dependent on the type of combustion system used (i.e., lean premix or diffusion flame combustion system). A lean premix combustion system operates with a lower flame temperature compared to a diffusion flame combustion system, resulting in lower NO_X emissions. Because each CT utilizes DLN combustor technology, each CT is considered to operate with lean premix technology as defined in 40 CFR §63.6175. The lean premix gas-fired stationary combustion turbine category includes CTs that are 1) equipped to fire both gas and oil using lean premix technology, and 2) located at a major HAP source where all new, reconstructed, and existing stationary combustion turbines

[52] There was a stay for NESHAP Subpart YYYY in 2004 on all requirements, except for an initial notification; however, this stay was lifted on March 9, 2022. https://www.federalregister.gov/documents/2022/03/09/2022-04848/national-emission-standards-for-hazardous-air-pollutants-stationary-combustion-turbines-amendments

fire oil no more than an aggregate total of 1,000 hours during the calendar year. As described in Section 3 of this application and on the DEP7007 A Form included in **Appendix C**, the maximum total hours of FO operation per CT will be 1,080 hr/yr, and aggregate maximum FO operating hours will be 2,160 hr/yr. However, EKPC expects that the actual aggregate hours of FO operation will be less than 1,000 hr/yr. Therefore, the CTs will likely be lean premix gas-fired stationary CTs. If actual aggregate hours of FO operation exceed 1,000 hr/yr, EKPC will comply with the requirements for lean premix oil-fired stationary CTs. The requirements for lean premix gas-fired stationary CTs and lean premix oil-fired stationary CTs are included in **Table 5-1**.

All applicable provisions under NESHAP YYYY are documented on the DEP7007 Form V in **Appendix C**.

Table 5-1. NESHAP Subpart YYYY Applicable Requirements

Category	Requirement Summary	Citation
Emission limits	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup.	40 CFR §63.6100 Table 1
Operating limits	Maintain 4-hour average catalyst inlet temperature within the range suggested by the catalyst manufacturer, excluding data recorded during startup.	40 CFR §63.6100 Table 2
General compliance requirements	Maintain the affected source, including associated air pollution control and monitoring equipment, in a manner consistent with safety and good air pollution control practices.	40 CFR §63.6105
Performance Testing	Conduct an initial performance test within 180 days after startup in accordance with the procedures in §63.6120 and submit a Notification of Compliance Status containing the results.	40 CFR §63.6110 40 CFR §63.6120 40 CFR §63.6130 Table 3 Table 4
	Conduct subsequent performance tests annually in accordance with the procedures in §63.6120.	40 CFR §63.6115 40 CFR §63.6120 Table 3
Monitoring Requirements	Monitor the oxidation catalyst inlet temperature on a continuous basis at all times that the source is operating. Do not use data during malfunctions, associated repairs, or quality assurance/quality control activities in data averages and calculations.	40 CFR §63.6125(a) 40 CFR §63.6135
	For lean premix gas-fired stationary combustion turbines, monitor and record distillate oil usage daily with a non-resettable hour meter to measure the number of hours that distillate oil is fired.	40 CFR §63.6125(d)
	Develop and implement a CMS quality control program.	40 CFR §63.6125(e)
	Demonstrate compliance by maintaining oxidation catalyst within the catalyst manufacturer's suggested inlet temperature range.	40 CFR §63.6140(a) Table 5
Notification Requirements	Submit an initial notification within 120 days after startup.	40 CFR §63.6145(b)
	Submit a notification of intent to conduct an initial performance test at least 60 days prior to conducting the initial performance test.	40 CFR §63.6145(e)
	Submit a Notification of Compliance Status within 60 days following the completion of a performance test.	40 CFR §63.6145(f)
Reporting Requirements	Submit a semi-annual compliance report in CEDRI by January 31 and July 31 each year.	40 CFR §63.6140(b) 40 CFR §63.6150(a)

Category	Requirement Summary	Citation
		40 CFR §63.6150(g) Table 6
	For lean premix gas-fired stationary combustion turbines, submit an annual report of distillate oil firing in CEDRI by January 31 each year.	40 CFR §63.6150(e)
	Submit a performance test report in CEDRI within 60 days after completing each required performance test.	40 CFR §63.6150(f) 40 CFR §63.6150(g)
Recordkeeping Requirements	Keep copies of all notifications, performance tests, startup events, air pollution control equipment maintenance, and deviations for five years.	40 CFR §63.6155 40 CFR §63.6160
	For lean premix gas-fired stationary combustion turbines, keep records of daily fuel usage monitors.	40 CFR §63.6155(b)

5.2.3 NESHAP Subpart ZZZZ – Reciprocating Internal Combustion Engines (Applicable)

40 CFR 63 *Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines* (RICE MACT) regulates HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. The project includes two stationary RICE: 1) EU21 Diesel-Fired Generator/Engine and 2) EU22 Diesel Pump/Engine.

Pursuant to 40 CFR §63.6590(c)(6), a new emergency or limited use stationary RICE with a site rating of less than or equal to 500 bhp located at a major source of HAPs (e.g., 310 hp Emergency Diesel Driven Fire Pump engine), must meet the requirements of RICE MACT by meeting the requirements of NSPS IIII for compression ignition engines. No further requirements apply for such engines under this part. Therefore, the EU22 Diesel Pump/Engine will satisfy the requirements of RICE MACT by meeting the requirements of NSPS IIII.

For the EU21 Diesel-Fired Generator/Engine, pursuant to 40 CFR §63.6590(b)(1) and (b)(1)(i), EKPC does not have to meet the requirements of RICE MACT and of 40 CFR 63, Subpart A except for the initial notification requirements of 40 CFR §63.6645(f).

5.2.4 NESHAP Subpart DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Applicable)

40 CFR 63 *Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* (Boiler MACT) applies to industrial, commercial, or institutional boilers or process heaters, as defined in 40 CFR §63.7575 that are located at, or are part of, a major source of HAP, except as specified in 40 CFR §63.7491. Boiler MACT applies to each new, reconstructed, or existing affected source, where the affected source includes the collection of all existing industrial, commercial, and institutional boilers and process heaters within an applicable subcategory defined in 40 CFR §63.7575 and each new or reconstructed industrial, commercial, or institutional boiler or process heater.

The Auxiliary Boiler (EU20) is an industrial boiler (78.32 MMBtu/hr), and thus will be subject to Boiler MACT. The Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24), which are equipped with burners with a heat input capacity of between 9 and 12 MMBtu/hr, are classified as process heaters, and thus will also be subject to Boiler MACT. As these combustion units are designed to use NG as the sole fuel for combustion, they will be categorized as "units designed to burn gas 1 fuels" per 40 CFR §63.7499.

EKPC plans to install multiple NG-fired HVAC units within buildings that are associated with the project. The specific make and model will not be known until later in the project development phase. The HVAC systems in the new buildings will be supported by seven (7) NG-fired heaters rated at 5.5 MMBtu/hr each and 14 NG-fired heaters rated at 0.061 MMBtu/hr each. These heaters do not meet the definition of a process heater in 40 CFR §63.7499, as they do not transfer heat to a process material for use in a process unit, and they are used for comfort and space heat. Therefore, the HVAC units are not subject to Boiler MACT.

Pursuant to 40 CFR §63.7500(a), the Auxiliary Boiler (EU20) and Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24) must comply with the emission limits and work practice standards presented in Tables 1 through 3 of the Boiler MACT and the operating limitations found in Table 4. Table 1 specifies emissions limitations for new boilers, but this table only includes emissions limitations for units designed to burn solid, liquid, and gaseous fuels defined under the "gas 2" fuel category. As the two new applicable units are considered "units designed to burn gas 1 fuels", they are not subject to any emissions standards. However, these units are subject to a limited number of work practice standards detailed in Table 3 of the rule. These include the requirement to conduct periodic tune-ups where the frequency of the tune-up is dependent on the heat input capacity of the boiler and the presence of a continuous oxygen trim system that maintains an optimum air-to-fuel ratio.

- Per 40 CFR §63.7500, EKPC must conduct a tune-up of the Auxiliary Boiler and NG-Fired Dew Point Heater No. 1 annually as specified in 40 CFR §63.7540(a)(10), unless the units have continuous oxygen trim systems that maintains an optimum air to fuel ratio. The first tune-up must be no later than 13 months after the initial startup of each boiler, per 40 CFR §63.7515(d).
- Per 40 CFR §63.7500, EKPC must conduct a tune-up of the NG-Fired Dew Point Heater No. 2 and 3 biennially as specified in 40 CFR §63.7540(a)(11).
- Per 40 CFR §63.7530(f), EKPC must submit a notification of compliance status containing the results of the initial compliance demonstration according to the requirements in 40 CFR §63.7545(e).
- Per 40 CFR §63.7540(b), EKPC must report any instances it did not meet the tune-up requirements and reported according to the requirements of 40 CFR §63.7550.
- Per 40 CFR §63.7545, EKPC must submit an initial notification no later than 15 days after the actual date of startup.
- Per 40 CFR §63.7550, EKPC must submit a compliance report annually.
- Per 40 CFR §63.7555, EKPC must keep records of each notification and report submitted for 5 years following the date of each occurrence.

EKPC has documented the relevant Boiler MACT provisions on DEP7007 V Form in **Appendix C**.

5.2.5 NESHAP Subpart UUUUU – Coal & Oil-Fired Electric Utility Steam Generating Units (Applicable)

40 CFR 63 *Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* is referenced to in short as the Mercury and Air Toxics Standards (MATS) and, applies to electric utility steam generating units (EUSGUs) that combust coal or oil.[53] C2 is currently subject to MATS as a coal-fired EUSGUs, which is defined as follows:

> *Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more*

[53] 40 CFR 63.9980

than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Following the project, EKPC anticipates that C2 will be capable of firing 100% coal or 100% NG at any given time. However, on an annual basis, EKPC expects that more than 15% of the annual average heat input will remain on coal, and the unit will continue to operate as a coal-fired EUSGU.

If at any point following the project, C2 becomes a NG-fired EUSGU, pursuant to 40 CFR §63.9983(b), C2 would no longer be subject to MATS.

MATS was last revised May 7, 2024, in 89 FR 38564. The changes that impact C2 are listed as follows:

- Reduction of Table 1 emission limit for existing coal-fired EGUs.
- Implementation of PM CEMS requirement for existing coal-fired EGUs to demonstrate compliance with the filterable PM emission limit per 40 CFR §63.10007(c) and §63.10010(i) beginning July 6, 2027. This requirement replaces the use of a PM continuous parameter monitoring system (CPMS).
- Requirement to demonstrate compliance with the filterable PM limit unless approval is received for the use of a non-mercury HAP metals CMS per §63.10010(i) beginning July 6, 2027.
- Removal of the low emitting EGU (LEE) option for filterable PM, non-mercury HAP metals, or individual non-mercury HAP metals beginning July 6, 2027.
- Requirement to choose paragraph (1) of the "startup" definition in §63.10042 for the EGU after January 2, 2025.

Pursuant to 40 CFR §63.9983(a), any unit designated as a major source stationary combustion turbine subject to NESHAP YYYY is not subject to MATS. As such, EU18 and EU19 are not affected sources for MATS and will not be subject to the MATS rule.

5.3 Compliance Assurance Monitoring (40 CFR 64)

The CAM regulations apply to pollutant-specific emission units (PSEU) at a major source under the Title V operating permit program that satisfy the following criteria as detailed in 40 CFR §64.2(a):

- 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 §64.2(b);
- The unit uses a control device to achieve compliance with any such 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.

Title V permit applicants must prepare and submit a CAM Plan for subject units as part of Title V permit applications. The CAM Plans are intended to document the methods that will be followed to provide an on-going and reasonable assurance of compliance with emission limits. For a subject unit using a control device with post-controlled emissions exceeding the major source threshold (referred to as large pollutant-specific emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V air operation permit application. For a subject unit, with post-control emissions less than the major source threshold, a CAM plan is not required until the first Title V air operation permit renewal application. The only new or modified units associated with this project that potentially trigger CAM requirements are C2 and the CTs.

5.3.1 C2 CAM Applicability

As the Cooper Project includes the C2 Co-Firing Project, assessment of CAM applicability to C2 is necessary. The existing Title V permit includes CAM provisions for PM emissions from C2. As shown in the permit, EKPC is using a PM CEMS as the indicator of compliance of the monitoring requirement for particulate matter. The excursion level is set at 0.027 lb fPM/MMBtu over a six-hour averaging period, consistent with the three two-hour U.S. EPA RM 5 performance tests that have been conducted as the compliance demonstration method for the CAM applicable PM limits.

When any coal is fired by itself or with NG, EKPC will operate the PJFF and maintain compliance with the CAM Plan shown in the permit. If C2 employs spud burners on all available 18 burners, it will be unnecessary to engage the PJFF or account for any controls from the PJFF on 100% NG combustion, and CAM will not apply.

Pre-control emissions of SO_2 and NO_X from C2 are also above the 100 tpy threshold. However, EKPC operates SO_2 and NO_X CEMS as required in a Part 70 permit. Since the operation of CEMS is a continuous compliance determination method as defined in 40 CFR §64.1, CAM does not apply per §64.2(2)(b)(1)(vi). Cooper Station will continue to operate CEMS post-project to demonstrate compliance with applicable SO_2 and NO_X emission limits.

The C2 boiler does not utilize control devices to reduce emissions of any other pollutants for which the pre-control emissions exceed the Title V major source thresholds, with the exception of HAP regulated under NESHAP Subpart UUUUU. The HAP emission limits are exempt from CAM per 40 CFR §64.2(b)(1)(i).

5.3.2 Turbine CAM Applicability

The proposed CTs utilize air pollution controls to reduce emissions of NO_X, CO, VOC, and formaldehyde.

The CTs will be subject to NSPS Subpart KKKK, which includes a NO_X standard. Since the NSPS Subpart KKKK NO_X standard is a CAA Section 111 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). The CTs will also be subject to a NO_X BACT limit. However, the CTs will be equipped with CEMS, which will be required to demonstrate compliance with the NO_X BACT limit in a Part 70 permit. Since the operation of CEMS is a continuous compliance determination method as defined in 40 CFR §64.1, CAM does not apply per §64.2(2)(b)(1)(vi).

The CTs will also be subject to NESHAP Subpart YYYY, which includes a formaldehyde standard. Formaldehyde emissions from each turbine are less than the Title V major source threshold, therefore, CAM does not apply. Further, NESHAP Subpart YYYY is a CAA Section 112 standard that was promulgated after November 15, 1990 and is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i).

The proposed CTs will be subject to BACT limits for CO and VOC emissions. For CO, EKPC plans to install a CO CEMS on the CTs; therefore, CO emissions from the CTs would be exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i).

Since emissions of VOC are only controlled during steady state operation, and are not controlled during startup and shutdown, CAM applicability is evaluated based on 1,080 hours per year of FO steady state operation, and 7,680 hours per year of NG steady state operation. Using this approach, VOC emissions are 19.0 tpy pre-control, and 13.3 tpy post-control. Since pre-control emissions of VOC are less than the Title V major source threshold, CAM does not apply to VOC.

If startup and shutdown emissions are required to be included in the CAM applicability evaluation, despite being uncontrolled, post-control emissions of VOC exceed the Title V major source threshold. EKPC proposes compliance with the oxidation catalyst parametric monitoring requirements of NESHAP Subpart YYYY as CAM VOC.

5.4 Risk Management Plans (40 CFR 68)

Subpart B of 40 CFR 68 (RMP Rule) outlines requirements for risk management prevention plans pursuant to Section 112(r) of the CAA. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility.

The facility is and will also continue to be subject to the General Duty Clause under the CAA Section 112(r)(1), which states:

> *The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.*

The Cooper Project will use aqueous ammonia at a concentration not to exceed 19%, which is not regulated under the RMP program. Thus, the installation of the CCGT EGU will not affect the plant's current regulated status under the RMP Rule.

5.5 Stratospheric Ozone Protection Regulations (40 CFR 82)

The requirements originating from Title VI of the CAA, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A, B, and F of 40 CFR 82 are potentially applicable to the facility. In particular, 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[54] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. EKPC will continue to comply with 40 CFR 82 Subpart F. The applicable provisions under 40 CFR

[54] 40 CFR 82.150

82 are already contained in the plant's existing Title V permit and the project will not necessitate a change to these provisions.

5.6 Interstate Trading Programs

Starting with the ARP mandated by the 1990 Clean Air Act Amendments, EPA has developed several market-based "cap and trade" regulatory programs. All market-based regulatory programs are overseen by EPA's Clean Air Markets Division (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to EKPC are:

- Acid Rain Program (1990 – ongoing)
- Cross-State Air Pollution Rule (2015 – ongoing)

5.6.1 Acid Rain Applicability

To reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the CAA Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. Kentucky incorporates the ARP by reference per 401 KAR 52:060, Acid Rain Permit*.* Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase II implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The proposed CTs will be utility units subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring); however, the CTs will not be subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the proposed CTs do not have the capability to burn coal. EKPC is required to apply for the ARP permit at least two years prior to commencing operation of the proposed CTs.[55] Under 40 CFR 75 of the ARP, EKPC is required to operate various CEMS for their coal-fired assets.[56] Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of the monitors within 90 unit operating days or 180 calendar days (whichever occurs first) of commencement of commercial operation, quarterly reports, and an annual compliance certification.

5.6.2 Cross-State Air Pollution Rule

CSAPR implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule. Upon reviewing the existing Title V permit for Cooper Station, EKPC is requesting that the Division consider removing the CAIR requirements.

C1 and C2 are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Program, and CSAPR SO_2 Trading Program.

EKPC's proposed CTs will be affected sources under this regulation, and must comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR §97.1030 through 97.1035. EKPC is required to monitor emissions of SO_2, NO_X, and maintain sufficient allowances under CSAPR for its operations. Monitoring requirements for NO_X mass emissions and individual unit heat input, including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate,

[55] 40 CFR 72.30(b)(2)(ii)

[56] While not subject to ARP NO_X provisions per Part 76, Part 75 monitoring requirements for NO_X apply as referenced by CSAPR.

CO_2 or O_2 concentration, and fuel flow rate, as applicable, typically tie back to ARP requirements per 40 CFR Part 75.[57] EKPC will comply with the applicable requirements of this rule upon startup of the CTs.

5.7 Kentucky SIP Regulations

Emissions from new and modified equipment associated with the proposed project are also potentially subject to KAR. Applicability to selected SIP regulations worth noting is discussed in the following subsections. The legacy Cooper sources' regulatory applicability for KAR rules documented in the current Title V Permit are not affected by the proposed Cooper Project, and thus, a state air regulatory review for the legacy Cooper plant sources is not discussed herein.

5.7.1 401 KAR 51:017 and 52:020 – PSD and Title V Permitting Programs (Applicable)

The Cooper Station is located in an unclassified/attainment area for all criteria pollutants. Therefore, with respect to the Kentucky NSR permitting program, only PSD requirements could potentially apply to the source. As discussed in **Section 4,** emissions increases of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4, and GHG from the Cooper Project exceed the applicable PSD triggering thresholds, and thus, PSD permitting requirements for these pollutants are addressed in this application. Applicable PSD permitting requirements include the completion of a BACT analysis, which is presented in **Sections 6** through **10**, and a PSD Air Quality Analysis and Additional Impacts Analysis, which will be presented in **Volume 2**.

The Cooper Project and the existing legacy Cooper operations are regulated under the Title V permit program. Pursuant to 401 KAR 52:020, Section 3, a major source shall not construct, reconstruct, or modify without a permit or permit revision, except as provided for administrative revisions, minor revisions, off-permit changes, and 502(b)(10) changes. This application package provides information required under 401 KAR 52:020, Section 4, 5, and 16 for the purposes of a SPR to a Title V and PSD source. Completed DEP7007 series application forms for the proposed project are provided in **Appendix C** of the application package.

5.7.2 401 KAR 53:010 – Kentucky Ambient Air Quality Standards for Gaseous Fluorides (Not Applicable)

401 KAR 53:010 establishes ambient air quality standards (AAQS) for HF and total fluorides for the state of Kentucky. Total fluoride standards are expressed as a dry weight measure of fluoride ions in and on forage for consumption by grazing ruminants. Concentrations are assessed on a one-month, two-month, and growing season average basis. Gaseous fluoride standards are expressed as ambient concentration limits of HF for both short-term and annual averaging periods. The fluoride standards apply generally to all sources but are typically only addressed in permit applications and associated permits for sources with expected or measurable fluoride emissions. The regulatory text in 401 KAR 53:010 does not specify when or how a source has to evaluate compliance with the ambient standards for fluorides.

The new emission units associated with the Cooper Project are not sources of gaseous fluoride emissions, and thus will not result in any ambient concentrations exceeding the gaseous fluoride AAQS.

[57] 40 CFR §97.1029(a)(1) Requirements for installation, certification, and data accounting

5.7.3 401 KAR 59:010 – New Process Operations (Applicable)

Pursuant to 401 KAR 59:010, Section 1(1), particulate emissions from new process operations not subject to other emission standards with respect to particulates in Chapter 59 and that are constructed after July 2, 1975, are subject to this generally applicable rule. The affected operations covered include any "method, form, action, operation, or treatment of manufacturing or processing, and shall include any storage or handling of materials or products, before, during, or after manufacturing or processing." Section 3 of the rule establishes the following opacity and mass emissions standards:

- Pursuant to 401 KAR 59:010, Section 3(1)(a), the continuous emission into the open air from a control device or stack associated with the affected facility shall be less than 20 percent opacity.

- Pursuant to 401 KAR 59:010, Section 3(2), the PM emissions into the open air from a control device or stack associated with the affected facility shall not exceed the process weight equation limitation of $E = 3.59(P)^{0.62}$, where E = PM emission limit in lb/hr and P = process rates greater than 0.5 tph and less than 30 tph. For process weight rates equal to and less than 0.5 tph, E = 2.34 lb/hr. For process weights in excess of 30 tph, $E = 17.31(P)^{0.16}$.

This regulation will be applicable to the mechanical draft cooling tower (EU25) in accordance with current Division interpretations of this regulation concerning cooling towers generally. Based on its design and characteristics, the cooling tower can be presumed to be in compliance with 401 KAR 59:010 when it is operated and maintained in accordance with the manufacturer's specifications and recommendations.

5.7.4 401 KAR 59:015 – New Indirect Heat Exchangers (Applicable)

This regulation applies to equipment, apparatus, or contrivances 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 into contact with or add to the products of combustion. Affected sources must have a heat input capacity greater than 1 MMBtu/hr.

The Auxiliary Boiler (EU20), Fuel Gas (Dewpoint) Heaters (EU17, EU23, and EU24), and HVAC Heaters rated at 5.5 MMBtu/hr (EU29A) meet the definition of indirect heat exchangers under 401 KAR 59:015 and are new affected facilities. Section 4 of 401 KAR 59:015 establishes opacity standards and heat input-based PM emission limits. Pursuant to 401 KAR 59:015, Section 4(2), opacity of continuous emissions from the two (2) indirect-fired heat exchangers are limited to 20%, except that a maximum of 40% shall be allowed for a maximum of six (6) consecutive minutes in any sixty (60) minute period during fire-box cleaning or soot blowing events.

The applicable PM emission limit is determined based on the total heat input capacity for all the affected facilities at the source at the time of construction of the new units. A different heat input-based PM allowable emission rate applies depending on whether the total heat input capacity for the facility is less than 10 MMBtu/hr, between 10 MMBtu/hr and 250 MMBtu/hr, or above 250 MMBtu/hr. The sum of the heat input capacities for the two new units plus the existing affected facilities is greater than 250 MMBtu/hr; therefore, the allowable PM emission factor using the applicable algorithm presented in 401 KAR 59:015, Section 4(1)(b), is 0.10 lb PM/MMBtu. The potential PM emission factor from combusting NG in the new heat exchangers is orders of magnitude lower than the allowable PM emission rate, so EKPC will be in compliance with these emission limits when burning NG.

Section 5 of the rule establishes SO_2 emissions standards. The SO_2 emissions standard is also limited based on the total heat input capacity for all affected facilities at the source. A different heat input capacity-based allowable emission rate algorithm applies based on the type of fuel to be burned (e.g., solid, liquid, or gaseous) and whether the total, facility-wide affected facility heat input capacity falls within one of the same ranges discussed above for the PM emission limit derivation. The allowable SO_2 emission factor using the applicable algorithm presented 401 KAR 59:015, Section 5(1)(b)1, is 0.8 lb SO_2/MMBtu. Again, the potential SO_2 emission factor from combusting NG in the Cooper Station's 401 KAR 59:015-affected units is orders of magnitude lower than the allowable SO_2 emission rate, so EKPC will be in compliance with these emission limits when burning NG.

401 KAR 59:015 was revised, effective March 9, 2018. Changes were made to the startup, shutdown, and malfunction (SSM) provisions of the rule; whereby work practice standards must be met during periods of SSM and certain procedures must be followed for startup and shutdown periods (now defined in the rule). Because the Auxiliary Boiler and all Fuel Gas (Dewpoint) Preheaters are subject to 40 CFR 63, Subpart DDDDD, the units must meet the work practices standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD pursuant to 401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a). The HVAC Heaters subject to 401 KAR 59:015 are not subject to 40 CFR 63, Subpart DDDDD and as such will comply with the SSM provisions of 401 KAR 59:015, Section 7.

5.7.5 401 KAR 59:050 – New Storage Vessels for Petroleum Liquids (Not Applicable)

Pursuant to 401 KAR 59:050 Section 2(1), an "affected facility" is a storage vessel for petroleum liquids with storage capacity greater than 580 gallons. Pursuant to 401 KAR 59:050, Section 2(3), "petroleum liquids" does not mean diesel FOs amongst others. Therefore, the planned FO tanks would not fall into the definition of "petroleum liquids" so they are exempt from the regulation.

5.7.6 401 KAR 63:010 – Fugitive Emissions (Applicable)

The paved haul roads have the potential to generate fugitive PM emissions that are regulated under 401 KAR 63:010. 401 KAR 63:010 is a generally applicable standard that requires reasonable precautions be taken to prevent airborne PM emissions. In accordance with 401 KAR 63:010, EKPC will take reasonable precautions as described in the regulation to prevent fugitive emissions from the project affected sources. EKPC will also ensure no visible fugitive dust emissions from the proposed plant are discharged beyond the property line. Subject sources are indicated in the applicable DEP7007 V Form included in **Appendix C.**

5.7.7 401 KAR 63:020 – Potentially Hazardous Matter or Toxic Substances (Applicable)

Kentucky regulates the emissions of toxic air pollutant emissions through 401 KAR 63:020. The Division can require that dispersion modeling or other analyses be completed by facilities at permit renewal or when constructing equipment when there is an increase in toxic pollutant emissions, as defined under 401 KAR 63:020, Section 2(2), deemed to be "significant." This is done so that there is a documented basis for affirming that a facility does not cause an adverse impact. However, pursuant to 401 KAR 63:020, Section 1, the requirements of this rule are applicable only to the extent that such emissions are not elsewhere subject to the provisions of the KAR.

Emissions from all NESHAP/MACT-affected emission units have been incorporated in 401 KAR 63:002, Section 2. Since the toxic air pollutant emissions are already regulated under a NESHAP/MACT, no additional requirements under 401 KAR 63:020 will apply.

All of the Cooper Project combustion units are sources of trace HAP/air toxic emissions generated as normal byproducts of NG combustion. Some relatively small NG combustion systems and low emitting sources of particulate-based air toxics included in the project scope have the potential to generate trace quantities of air toxics, but a "no adverse impact" determination can be qualitatively asserted based on the negligible emissions levels from these sources. Therefore, EKPC does not intend to prepare a refined air dispersion modeling analysis to evaluate ambient impacts of air toxics emissions from the proposed project. Rather, simplified screening techniques will be used to demonstrate the proposed sources of air toxics emissions not subject to a NESHAP and included in the proposed project scope will not cause or contribute to adverse impacts.

6. BACT ANALYSIS METHODOLOGY

As the proposed project is expected to result in emission increases of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 Mist, and GHG emissions in excess of the NSR major modification thresholds, an analysis to ensure the implementation of BACT is required for the new and modified emission units being proposed as part of this project that would have potential emissions for any of these pollutants. A technical review has been performed to investigate and identify emission controls that have recently been determined by various permitting authorities across the U.S. to satisfy BACT requirements.

6.1 BACT Introduction

Any new major stationary source or any major modification at an existing stationary source subject to PSD review must conduct an analysis to ensure the use of BACT. The requirement to conduct a BACT analysis is set forth in 40 CFR 52.21 and 401 KAR 51:017 Section 8. Kentucky's PSD regulations define BACT as:[58]

> *"an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification* and:
>
> *(a) Is determined by the cabinet on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant;*
>
> *(b) Does not result in emissions of a pollutant that would exceed the emissions allowed by an applicable standard of 40 C.F.R. Parts 60 and 61; an*d
>
> *(c) Is satisfied by a design, equipment, work practice, or operational standard or combination of standards approved by the cabinet, if:*
> 1. *The cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would* make the imposition of an emissions standard infeasible;
> 2. *The standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice or operation; and*
> 3. *The standard provides for compliance by means that achieve equivalent results."*

In accordance with Kentucky's PSD regulations, BACT is determined on a pollutant-by-pollutant basis for each pollutant for which there is a significant net emissions increase. The BACT review covers new and modified emission units associated with the project.

BACT is based on the source as proposed: it does not require consideration of control alternatives that would fundamentally redesign it. Utility Air Regulatory Group v. EPA, 134 S.Ct. 2427, 2448 (2014) states "For one, BACT is based on "control technology" for the applicant's "proposed facility," [CAA] § 7475(a)(4); therefore, it has long been held that BACT cannot be used to order a fundamental redesign of the facility."

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[58] 401 KAR 51:001 Section 1 (25).

As previously discussed, the purpose of the Cooper Project is for EKPC to be able to provide reliable and affordable power to its members at all times. The Cooper Project as proposed accomplishes this through fuel flexibility assuring the ability to generate power under reasonably foreseeable events (e.g., renewable generation unavailable, natural gas curtailment). Consideration of other types of power generation (e.g., energy storage) as an alternative to the Cooper Project would require a fundamental redesign and thus is not required.

The emissions increases are presented in **Section 4** along with each pollutant's corresponding PSD SER. As shown in **Section 4**, the project emission increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and H_2SO_4 will exceed the SER for non-GHG regulated NSR pollutants and the "subject to regulation" threshold for GHG. Therefore, these pollutants are subject to BACT review. Consistent with the approach used by KDAQ for other permitted projects, the "top-down" BACT analysis is organized by pollutant and by emissions source category and is presented in the following sections of the application. BACT emission limitations have been proposed to address all operations for each emissions source considered in the analysis.

6.2 BACT Determination Methodology

Consistent with KDAQ's implementation of the BACT requirements under 401 KAR 51:017, BACT for the proposed project has been evaluated via a "top-down" approach. Under this identified top-down approach, the most stringent control available for a similar or identical source or source category is identified. This control option is used to establish the BACT emission limitation unless the applicant can demonstrate (and the permitting authority agrees) that it is not "achievable" due to technical infeasibility or not being cost-effective or because there would be other adverse environmental or energy consequences of implementing the technology. If the top control alternative is eliminated, then the next most stringent level of control is evaluated. This process continues until the control option under consideration cannot be eliminated by any source specific adverse environmental, energy, or economic impacts.

6.2.1 BACT Step 1 - Identify All Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable. Options that would fundamentally redefine a source are not considered "available". The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical infeasibility, not being cost-effective, or environmental and energy impacts, all control technologies with potential application to the emission unit under review should be identified.

The following resources are typically consulted when identifying potential technologies:

1. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Previous engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

Potentially applicable emission control technologies were identified by researching the EPA's RBLC database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC, a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

RBLC database searches were performed for each emission unit type to initially identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years (or further back in the RBLC database's historical record where necessary to ensure an adequate number of representative BACT determinations were included in the RBLC output) for emission sources comparable to the proposed new and modified units included in the Cooper Project scope. **Appendix D** contains the output from the RBLC search results.

6.2.2 BACT Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether a technology is feasible is whether it has been "demonstrated" in practice. If so, it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination. Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available." Control technologies in the research and development and pilot scale phases are not considered available. An available control technology is presumed to be applicable if it has been permitted or implemented by a similar source.

Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative.

6.2.3 BACT Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

6.2.4 BACT Step 4 - Evaluate Most Effective Controls and Document Results

After identifying available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, then it is selected as BACT. Alternatively, if adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until an achievable control technology is identified.

6.2.5 BACT Step 5 - Select BACT

In the final step, one pollutant specific control option establishes BACT for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

BACT must reflect emission rates less than or equal to any applicable NSPS or NESHAP emission standards for the source under review. In any case where NSPS or NESHAP emission limits for certain pollutants will apply to proposed equipment and effectively set the floor for BACT for these units, the Step 5 BACT selection process identifies these applicable NSPS or NESHAP standards and notes how they were considered in setting the proposed BACT limit. It is important to note that applicable NSPS and NESHAP emission standards are proposed for revision or facing legal challenges. The proposed revisions and legal challenges have been taken into consideration in proposing BACT, and EKPC understands its obligation to comply with all applicable NSPS and NESHAP upon startup.

6.3 BACT Requirements

For this project, the BACT requirement applies to each new and modified emission unit which will emit pollutants subject to PSD review. The proposed facility is subject to PSD permitting for CO, VOC, NO_X, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. The control technology analysis for $PM_{2.5}$ addresses only direct $PM_{2.5}$ emissions since separate analyses were performed for $PM_{2.5}$ precursors (i.e., NO_X). **Table 6-1** identifies the pollutants considered in the PSD BACT analysis for each emission unit.

Table 6-1. Pollutants Evaluated in the BACT Analysis for Each Emission Unit

Equipment	**CO** (Yes/No)	**NO_x** (Yes/No)	**$PM/PM_{10}/PM_{2.5}$** (Yes/No)	**VOC** (Yes/No)	**H_2SO_4 Mist** (Yes/No)	**GHG** (Yes/No)
EU18 Unit 3 CT EU19 Unit 4 CT	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU2 (C2) Co-Fired Boiler	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU20 NG-Fired Auxiliary Boiler	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU17, EU23, & EU24 NG-Fired Dewpoint Heaters 1, 2, & 3	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU29A/B NG-Fired Heaters	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU21 Diesel-Fired Generator/Engine	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU22 Diesel Pump/Engine	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU25 Cooling Tower	No	No	**Yes**	No	No	No
EU26A, EU26B, EU27, & EU28 External FO Storage Tanks	No	No	No	**Yes**	No	No
EU32 CCGT Haul Roads	No	No	**Yes**	No	No	No
EU30 & EU31 Circuit Breakers	No	No	No	No	No	**Yes**
EU33 NG Piping Fugitives	No	No	No	**Yes**	No	**Yes**
EU34 H_2SO_4 Storage Tank	No	No	No	No	**Yes**	No

7. BACT ANALYSIS FOR CCGT

The proposed CCGT will be fired with both NG and FO. As discussed in Section 6.2.1, one source of data used in the analysis is the RBLC; **Appendix D** provides a listing of the recent RBLC determinations for combustion turbine power generation facilities.

EKPC performed an RBLC database search using the following criteria:

- Process Type Code:
  - 15.210 (Combined Cycle & Cogeneration >25MW, NG-Fired)
  - 15.290 (Combined Cycle & Cogeneration >25MW, Liquid Fuel & Liquid Fuel Mixtures)

The RBLC search results discussed within this section have been screened to exclude units that are not representative of the CCGT. This includes proposed new CCGT facilities which have not been constructed, CCGTs which have not undergone performance testing to demonstrate the achievability of the BACT emission limits, CCGT facilities that are not used exclusively for electricity generation, and CCGT facilities that are not comparable to the proposed CCGT due to fuel types or turbine size. For the sake of brevity, EKPC removed entries for units with a maximum capacity of less than 850 MMBtu/hr or 100 MW. Turbines smaller than approximately 100 MW are not directly comparable to larger "frame class" combustion turbines. Note that there are no RBLC entries for aeroderivative turbines with emission limits lower than the proposed BACT limits for the CCGT.

With respect to the level of the BACT limit, EKPC has only evaluated sources with more stringent (i.e., lower) permitted emissions limits in Step 5. As such, those units with equivalent or higher permitted emissions limits are not represented in the pollutant-specific RBLC summary tables in the following subsections. Information on those units with equivalent or higher emissions limits are included in the full RBLC tables within **Appendix D**.

7.1 CO BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for CO emissions from the CTs. Air pollution control strategies are evaluated using the top-down BACT approach. An oxidation catalyst system will be installed and operated to control CO emissions from NG- and FO-firing in each CT.

7.1.1 Background on Pollutant Formation

CO from the CCGT is a by-product of incomplete combustion. Conditions leading to incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

7.1.2 Identification of Potential Control Technologies (Step 1)

CO emissions can be reduced by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques involve good design of the combustion process and good combustion and operating practices. Post-combustion control can be done with an oxidation catalyst.

Table 7-1. Potential CO Control Technologies for CTs

Pollutant	Control Technologies
CO	Oxidation Catalyst EM_X™/$SCONO_X$™/METEOR™ Good Combustion Practices

7.1.2.1 Oxidation Catalyst

The basic chemical reactions in the exhaust stream resulting from application of an oxidation catalyst are as follows:

$CO + ½ O_2 \rightarrow CO_2$
$C_nH_m + (n + m/4) O_2 \rightarrow n CO_2 + (m/2) H_2O$
$C_nH_mO + (n + m/4 - 0.5) O_2 \rightarrow n CO_2 + (m/2) H_2O$
$2H_2 + O_2 \rightarrow 2H_2O$

The oxidation catalysts are formulated with precious metals (e.g., platinum group metals) and are coated on flow-through metal monoliths for minimum backpressure and compact design. Multiple catalyst formulations allow the flexibility to target specific conversion requirements, exhaust temperatures, and low SO_2 to SO_3 and NO to NO_2 conversions. Oxidation catalysts can provide greater than 90% destruction of CO, VOCs, formaldehyde, and other toxic compounds.[59] See Section 4.3 of **Appendix B** for the methodologies used to calculate the control efficiencies used for the emissions from the two new CTs.

7.1.2.2 EM_X™ / $SCONO_X$™ / METEOR™

EM_X™ (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X, CO, and VOC without a reagent, such as NH_3. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize NO_X (to potassium nitrate [$K(NO_3)$]), CO (to CO_2), and VOC.[60] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[61] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The $SCONO_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[62] METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc. and optimized by Cormetech. These systems use an oxidation catalyst that provides an equivalent level of control for CO emissions to other oxidation catalysts, and therefore, they do not separately need to be carried to the remaining steps of the turbine BACT analysis.

[59] https://www.jmsec.com/fileadmin/user_upload/pdf/brochures/jmsec_gas_turbine_oxidation_catalyst.pdf

[60] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[61] Ibid.

[62] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

7.1.2.3 Combustion Process Design and Good Combustion and Operating Practices

To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperatures as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NO_X emissions. Accordingly, it is critical to optimize oxygen availability with input air, while controlling temperature to minimize NO_X formation. Modern turbine control systems implement good combustion practices by using computer-based systems to adjust operating parameters automatically.

7.1.3 Elimination of Technically Infeasible Control Options (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

7.1.3.1 Oxidation Catalyst

Oxidation catalysts typically operate within a temperature range between 600 to 800°F.[63] In combined cycle operation, the presence of a HRSG to recover useful thermal output from the turbine exhaust gas lowers the gas temperature into the oxidation catalyst's operating range. The fuel used in the combustion turbine also impacts the effectiveness of an oxidation catalyst. When operating on FO, rather than NG, the emissions profile from the turbine, as well as the performance of the oxidation catalyst system, are impacted. Nevertheless, properly designed oxidation catalysts are capable of operating during both NG and FO operation. Thus, an oxidation catalyst is technically feasible for the proposed CTs.

7.1.3.2 Combustion Process Design and Good Combustion and Operating Practices Technical Feasibility

This represents the base case for design and operation of the combustion turbines.

7.1.4 Rank of Remaining Control Technologies (Step 3)

The only technically feasible add-on control technology to reduce emissions is the use of oxidation catalysts along with good combustion practices. As a technically feasible control option, it must be evaluated further in the BACT process.

7.1.5 Evaluation of Most Stringent Control Technologies (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for each CT. EKPC is proposing installation and operation of this option, alongside good combustion and operating practices (GCOP), as the most effective means for reducing emissions of CO from each CT.

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[63] U.S. EPA, *CATC Fact Sheet for Catalytic Incineration*, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

7.1.6 Selection of BACT (Step 5)

7.1.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The combustion turbines will not be subject to any NSPS or NESHAP standard for CO, and thus there is no floor for an allowable CO BACT limit. The CCGT will also not be subject to any CO emission limit under Title 401 of the Kentucky Administrative Rules.

7.1.6.2 Summary of RBLC Review

Table 7-2 and **Table 7-3** summarize the CO RBLC entries for combined cycle turbine units which combust NG and FO, respectively, pass the aforementioned exclusion criteria, and are more stringent than the CO limit proposed for the Cooper Station CCGT (2 ppmvd at 15% O_2). Detailed RBLC search results are provided in **Appendix D-1**.

Table 7-2. CO RBLC Entries for Natural Gas-Fired CTs

RBLC ID	Facility	Permit Date	Permitted CO Limit	Units	Averaging Period
CT-0158	CPV Towantic Energy Center	11/30/2015	0.9	ppmvd @ 15% O_2	1 Hour
CT-0161	Lake Road Energy Center	6/30/2017	0.9	ppmvd @ 15% O_2	1 Hour
NJ-0082	West Deptford Energy Station	7/18/2014	0.9	ppmvd @ 15% O_2	3 Hours
VA-0325	Greensville Power Station	6/17/2016	1	ppmvd @ 15% O_2	3-Hour
IL-0130	Jackson Energy Center	12/31/2018	1.5	ppmvd @ 15% O_2	3-Hour
MD-0042	Wildcat Point Generation Facility	4/8/2014	1.5	ppmvd @ 15% O_2	3-Hour

Table 7-3. CO RBLC Entries for Fuel Oil-Fired CTs

RBLC ID	Facility	Permit Date	Permitted CO Limit	Units	Averaging Period
CT-0161	Lake Road Energy Center	6/30/2017	1.8	ppmvd @ 15% O_2	1 Hour

As shown in **Appendix D**, more than 40 RBLC entries for combined cycle, heavy-duty frame-class combustion turbines utilizing oxidation catalyst and good combustion practices have approved BACT limits of 2 ppmvd.

The lowest emissions presented for comparable units range from 0.9 ppmvd to 1.5 ppmvd. These entries are discussed below.

0.9 ppmvd Emission Limit Entries
Three RBLC database entries with a CO BACT limit of 0.9 ppmvd were identified and all three are located in ozone nonattainment areas. These facilities and their locations are listed below, along with the ozone nonattainment status of each location:

- CT-0158 – CPV Towantic Energy Center – New Haven County, CT
  - Serious (2015)

- Severe (2008)

- CT-0161 – Lake Road Energy Center – Windham County, CT
  - Serious (2015)
  - Serious (2008)
- NJ-0082 – West Deptford Energy Station – Gloucester County, NJ
  - Serious (2015)
  - Marginal (2008)

As these facilities are located in ozone nonattainment areas, they are subject to NNSR requirements for VOC, which mandate the implementation of LAER rather than BACT. LAER, unlike BACT, solely focuses on achieving the most stringent emission limit without considering factors such as cost, energy consumption, or environmental impact. As discussed in **Section 7.2**, some control options for VOC, namely oxidation catalyst, are also effective at reducing CO emissions. CO emission limits for these sites therefore were ultimately set to comply with LAER requirements and are more stringent than what would have been required under BACT requirements. Furthermore, none of these sources with 0.9 ppmvd CO limits are the same make and model as the proposed F-class turbines.

1 – 2 ppmvd Emission Limit Entries

Three additional RBLC database entries were identified with limits ranging from 1 ppmvd to 1.5 ppmvd. These facilities and their locations are listed below, along with the ozone nonattainment status of each location:

- IL-0130 Jackson Energy Center – Will County, IL – 1.5 ppmvd
  - Moderate (2015)
- MD-0042 Wildcat Point Generation Facility – Cecil County, MD – 1.5 ppmvd
  - Marginal (2008) and Serious (2015)
- VA-0325 Greensville Power Station – Greensville County, VA – 1 ppmvd
  - Undesignated (in attainment)

With the exception of the Greensville Power Station, these facilities also are located in ozone nonattainment areas and would be subject to LAER rather than BACT for VOC. Although the Greensville Power Station CO limit is lower than the NG limit proposed for the CCGT at Cooper Station, it is for larger J-class turbines as compared to the proposed F-Class turbines for the Cooper Project, which are inherently capable of lower CO emissions. The proposed limit of 2 ppmvd is consistent with the overwhelming majority of limits (more than 40 RBLC entries) and is confirmed by other F-class turbines included in the RBLC database.

A limited number of RBLC entries indicate CO limits specifically applicable during FO operation. Of these, one unit determined to be comparable has a CO limit during FO operation lower than EKPC's vendor guarantee of 2 ppmvd @ 15% O_2: Lake Road Energy Center (CT-0161). Upon further review of the Lake Road Energy Center's operating permit, the unit is subject to a 4.0 ppmvd @ 15% O_2 CO FO limit at full load and a 5.0 ppmvd @ 15% O_2 during 75%-99% load. The CO limit reflected in the RBLC database, 1.8 ppmvd, was determined to be inaccurate. Additionally, the site is located in Windham County, which is designated as in Serious nonattainment for ozone under both the 2008 and 2015 standards, and thus would be subject to LAER for VOC emissions. All remaining comparable facilities in the RBLC indicate BACT emission limits greater than or equal to 2 ppmvd.

7.1.6.3 CO BACT Limit Selection – Steady-State Operation

Proposed Natural Gas Steady-State CO BACT Limit
EKPC is proposing BACT for the CCGT firing NG as the use of oxidation catalyst technology and good combustion practices. Based on data provided by the equipment vendor, EKPC proposes a BACT limit for CO of 2.0 ppmvd, corrected to 15% O_2, on a 30-day averaging basis during NG operation, excluding periods of startup, shutdown, and fuel-oil operation (see Section 7.7 for SU/SD BACT). EKPC proposes to demonstrate compliance via CO CEMS. The proposed limit is equivalent to many recently approved CCGT BACT limits and allows the flexibility needed to operate across a wide variety of operating conditions and maintain compliance.

Proposed Fuel Oil Steady-State CO BACT Limit
EKPC is proposing BACT for the CCGT firing FO as the use of oxidation catalyst technology and good combustion practices. Based on data provided by the equipment vendor, EKPC proposes a BACT limit for CO of 2.0 ppmvd, corrected to 15% O_2, on a 30-day averaging basis during fuel-oil operation, excluding periods of startup, shutdown, and NG operation (see Section 7.7 for SU/SD BACT). EKPC proposes to demonstrate compliance via CO CEMS.

7.2 VOC BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for VOC emissions from the CTs. Air pollution control strategies are evaluated using the top-down BACT approach. An oxidation catalyst system will be installed and operated to control VOC emissions from NG- and FO-firing in each CT.

7.2.1 Background on Pollutant Formation

VOC emissions result from incomplete combustion. VOCs are released into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process.

7.2.2 Identification of Potential Control Technologies (Step 1)

The available control technologies for VOC are listed below in **Table 7-4**.

Table 7-4. Potential VOC Control Technologies for CTs

Pollutant	Control Technologies
VOC	Oxidation Catalyst EM_X™/$SCONO_X$™/METEOR™ Good Combustion Practices

7.2.2.1 Oxidation Catalyst

Oxidation catalyst control technology is discussed in detail in Section 7.1.2.1.

7.2.2.2 EM_X™ / $SCONO_X$™ /METEOR™

EM_X™/ $SCONO_X$™/METEOR™ control technology is described in detail in Section 7.2.2.2. These systems use an oxidation catalyst that provides an equivalent level of control for VOC emissions to other oxidation catalysts, and therefore, they do not separately need to be carried to the remaining steps of the turbine BACT analysis.

7.2.2.3 Good Combustion Practices

Good combustion practices allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios. Good combustion practices involve the monitoring and adjustment of these parameters to ensure all turbine systems, including those intended to minimize pollutant formation, are operating as effectively and efficiently as possible. Modern turbine control systems are typically computer-based and can adjust operating parameters automatically, ensuring complete combustion to minimize VOC emission. This is considered the base-case for the proposed combustion turbines.

7.2.3 Elimination of Technically Infeasible Control Options (Step 2)

7.2.3.1 Oxidation Catalyst

Oxidation catalysts typically operate within a temperature range between 600 to 800°F.[64] The exhaust temperature from the combined cycle turbines falls well within the operating temperature of typical oxidation catalyst systems. Therefore, oxidation catalyst is considered technically feasible for the proposed turbines.

7.2.3.2 Good Combustion Practices

This represents the base case for design and operation of the combustion turbines.

7.2.4 Rank of Remaining Control Technologies (Step 3)

The only technically feasible add-on control to reduce emissions is the use of oxidation catalysts along with good combustion practices. As a technically feasible control option, it must be evaluated further in the BACT process.

7.2.5 Evaluation of Most Stringent Control Technologies (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for the proposed CTs. EKPC is proposing installation of oxidation catalyst with good combustion practices as the most effective means for reducing emissions of VOC from each CT.

7.2.6 Selection of BACT (Step 5)

7.2.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The combustion turbines will not be subject to any NSPS or NESHAP standard for VOC[65] and thus there is no floor for an allowable VOC BACT limit. Each CT will also not be subject to any VOC emission limit under Title 401 of the Kentucky Administrative Rules.

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[64] U.S. EPA, *CATC Fact Sheet for Catalytic Incineration*, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

[65] The CTs will be subject to 40 CFR 63 Subpart YYYY, which does limit emissions of formaldehyde, a component of VOC. However, for the purposes of this BACT analysis, EKPC is only considering standards that would apply to total VOC.

7.2.6.2 Summary of RBLC Review

As the selected BACT for VOC emissions relies on an oxidation catalyst and good combustion practices, EPA's RBLC database was reviewed to determine what has been established as a BACT emission requirement for comparable operations. **Table 7-5** includes RBLC search results that are more stringent than the proposed limit for natural gas in Step 5 (1 ppmvd at 15% O_2). There are three FO entries in the RBLC database that met the criteria for inclusion in the RBLC search for the proposed project, and the proposed VOC BACT limits for the three entries are greater than the proposed fuel oil limit (1 ppmvd at 15% O_2). Therefore, there are no RBLC search results that are more stringent than the proposed limit for fuel oil. Detailed RBLC search results are presented in **Appendix D-1.**

Table 7-5. VOC RBLC Entries for Natural Gas-Fired CTs

RBLC ID	Facility	Permit Date	Permitted VOC Limit	Units	Averaging Period
CT-0161	Lake Road Energy Center	6/30/2017	0.7	ppmvd @ 15% O_2	Not indicated
NJ-0082	West Deptford Energy Station	7/18/2014	0.7	ppmvd @ 15% O_2	N/A (stack test)
NY-0103	Cricket Valley Energy Center	2/3/2016	0.7	ppmvd @ 15% O_2	1 Hour
VA-0325	Greensville Power Station	6/17/2016	0.7	ppmvd @ 15% O_2	3-hour

As shown in **Appendix D**, over 30 RBLC entries for combined cycle, heavy-duty frame-class combustion turbines utilizing oxidation catalyst and good combustion practices have approved BACT limits of 1 ppmvd.

Three of the RBLC database entries in **Table 7-5** are located in ozone nonattainment areas or are part of the Ozone Transport Region (OTR), requiring NNSR. These facilities and their locations are listed below, along with the ozone nonattainment status of each location:

- CT-0161 – Lake Road Energy Center – Windham County, CT
  - Serious (2015)
  - Serious (2008)
- NJ-0082 – West Deptford Energy Station – Gloucester County, NJ
  - Serious (2015)
  - Marginal (2008)
- NY-0103 – Crickett Valley Energy Center – Dutchess County, NY
  - OTR

As these facilities are located in ozone nonattainment areas or the OTR, they are subject to NNSR requirements for VOC, which mandate the implementation of LAER rather than BACT. LAER, unlike BACT, solely focuses on achieving the most stringent emission limit without considering factors such as cost, energy consumption, or environmental impact. The VOC limits were ultimately set to comply with LAER requirements and are more stringent than what would have been required under BACT requirements.

Although the Greensville Power Station VOC limit is lower than the NG limit proposed for the CCGT at Cooper Station, it is for larger J-class turbines as compared to the proposed F-Class turbines for the Cooper Project, which are inherently capable of lower VOC emissions. Additionally, the facility also has a limit of 1.4 ppmvd when firing duct burners, resulting in an annual average value that is greater than 0.7 ppmvd and likely more consistent with the 1 ppmvd value proposed for Cooper Station.

7.2.6.3 VOC BACT Limit Selection – Steady-State Operation

Proposed Natural Gas Steady-State VOC BACT Limit
EKPC is proposing BACT for the CCGT firing NG as the use of oxidation catalyst technology and good combustion practices. EKPC proposes a BACT limit for VOC of 1.0 ppmvd, corrected to 15% O_2, on a 3-hour averaging basis during NG operation, excluding periods of startup, shutdown, and fuel-oil operation (see Section 7.7 for SU/SD BACT), which is the lowest level achievable. EKPC proposes to demonstrate compliance via initial performance testing and compliance with NESHAP YYYY. The proposed limit is equivalent to many recently approved CT BACT limits and allows the flexibility needed to operate across a wide variety of operating conditions and maintain compliance.

Proposed Fuel Oil Steady-State VOC BACT Limit
EKPC is proposing BACT for the CCGT firing FO as the use of oxidation catalyst technology and good combustion practices. EKPC proposes a BACT limit for VOC of 1.0 ppmvd, corrected to 15% O_2, on a 3-hour averaging basis during NG operation, excluding periods of startup, shutdown, and fuel-oil operation (see Section 7.7 for SU/SD BACT), which is the lowest level achievable. EKPC proposes to demonstrate compliance via initial performance testing and compliance with NESHAP YYYY. The proposed limit is equivalent to many recently approved CCGT BACT limits and allows the flexibility needed to operate across a wide variety of operating conditions and maintain compliance.

7.3 NO_X BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the CTs. Air pollution control strategies are evaluated using the top-down BACT approach. An SCR will be installed and operated to control NO_X emissions from NG- and FO-firing in each CT as part of the CCGT EGU Project.

7.3.1 Background on Pollutant Formation

There are different ways that NO_X emissions can be formed in a combustion turbine. The literature refers to five (5) primary "types" of NO_X: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. The three most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X.[66] For NG-fired and FO-fired units, most NO_X is thermal NO_X.

Thermal NO_X is formed mainly via the Zeldovich mechanism where the N_2 and O_2 molecules in the combustion air react to form nitrogen monoxide (NO).[67] Most thermal NO_X is formed in high temperature flame pockets downstream from the fuel injectors.[68] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NO_X is formed readily.[69] Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.

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[66] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[67] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document – NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[68] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[69] U.S. EPA, Clean Air Technology Center, *Technical Bulletin: Nitrogen Oxides (NO_X), Why and How They are Controlled*, EPA 456/F-99-006R. November 1999.

Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NO_X.[70] The contribution of prompt NO_X to overall NO_X is relatively small but increases in low- NO_X combustor designs. Prompt NO_X formation is also largely insensitive to changes in temperature and pressure.[71]

Fuel NO_X forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since NG and FO contain little fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from NG- or FO-fired combustion turbines.[72]

7.3.2 Identification of Potential Control Technologies (Step 1)

NO_X emissions can be reduced by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inert species (combustion products, for example) that limit initial NO_X formation, or both. Post-combustion control technologies use various strategies to chemically reduce NO_X to N_2 with or without the use of a catalyst.

Control options are provided in **Table 7-6**.

Table 7-6. Potential VOC Control Technologies for CTs

Pollutant	Type	Control Technologies
NO_X	Combustion Control	DLN Combustion Technology Water or Steam Injection Good Combustion Practices
	Post-Combustion Control	Multi-Pollutant Catalyst (EM_X™/$SCONO_X$™/ METEOR™) SCR SNCR

7.3.2.1 DLN Combustors

DLN combustor technology is used during NG combustion. DLN combustors premix air and fuel into a lean mixture prior to injection into the combustion turbine which significantly reduces peak flame temperature and thermal NO_X formation from NG combustion. Conventional combustors are diffusion controlled where fuel and air are injected separately.

7.3.2.2 Water or Steam Injection

Water or steam injection is only used during FO operation when the DLN system is not operating. While combusting FO, NO_X emissions can be further reduced by injecting water or steam into the flame area of the gas turbine combustor. Within every case supplied by the vendor steam injection will be used when

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[70] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[71] Ibid.

[72] Ibid.

combusting FO. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal NO_X.

7.3.2.3 Good Combustion Practices

Good combustion practices are operating practices and principles that allow the equipment to operate as efficiently as possible. The air-to-fuel ratio is one of the primary indicators of efficient combustion. Good combustion practices involve the monitoring of the air to fuel ratio to ensure the most efficient combustion. Modern turbine control systems implement good combustion practices by using computer-based systems to adjust operating parameters automatically.

7.3.2.4 EM_X™ / $SCONO_X$™ / METEOR ™

EM_X™ is described in detail in Section 7.2.2.

Estimates of CE for a $SCONO_X$™ system vary depending on the pollutant controlled. California Energy Commission reports a CE of 78% for NO_X reductions down to 2.0 ppm, and even higher NO_X reductions down to 1 ppm for some designs.[73] It should be noted that there are no RBLC entries for comparable combined cycle combustion turbine facilities with BACT limits below 2.0 ppm, and those facilities with limits of 2.0 ppm are all equipped with SCR, suggesting that $SCONO_X$ is, at best, no more effective at reducing NO_X emissions than SCR systems.

The METEOR™ catalyst uses ammonia, similar to standard SCR systems, to reduce NO_X emissions. The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs.[74]

7.3.2.5 SCR

SCR systems are used extensively in power generation applications including coal, oil, and combined cycle power plants. SCR is a post-combustion emissions control technique whereby aqueous ammonia is vaporized and injected into the combustion exhaust gases before they pass through a catalyst bed. In the presence of the catalyst, NO_2 and NO react with oxygen and ammonia to produce diatomic nitrogen and water.

The basic chemical reactions are as follows:

$$2\ NO + 2\ NH_3 + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + 3\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Small amounts of ammonia that are not consumed in the reaction result in low levels of ammonia stack emissions, known as ammonia slip. The performance of an SCR system depends primarily on the temperature of the exhaust gas as it passes through the catalyst. Although catalyst formulations have provided a continuum of temperature ranges, these are typically described by three temperature ranges for optimal NO_X reduction. A "normal" catalyst operates well at approximately 650°F, a "mid-range" catalyst operates well between 800 and 900°F, and a "hot" catalyst (generally zeolite based) can operate above a temperature of 1,100°F, although the effectiveness of NO_X removal declines as a function of the exhaust gas temperature. Conventional vanadium/titanium catalysts are commonly used in SCR applications and

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[73] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

[74] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 15-16.

have an optimal operating temperature in the 600 to 750°F range. The application of SCR on the combined cycle units can utilize a conventional catalyst which is located downstream of the CT itself, within the tube banks at an appropriate temperature region, near the 600-700°F range.

The catalyst used is typically stacked vertically with gas flow horizontally through the catalyst face. The catalyst has a much smaller pitch due to the limited particulate and plugging concerns and does not deactivate as rapidly due to minimal catalyst poisons in the flue gas.

7.3.2.6 SNCR

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6\ NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[75] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X.

7.3.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits.

7.3.3.1 DLN Combustion Technology Feasibility

DLN combustion technology is technically feasible for NG combustion and the proposed combustion turbines will have DLN combustors. DLN combustion technology is included in the following BACT steps but represents part of the base case for NO_X performance as it is inherent in the operation of the combustion systems.

As noted above in Section 7.3.2.1, DLN cannot be used during FO operation or during gas operation at low loads. Instead, diluent injection, typically water or steam, must be used for NO_X abatement during FO operations. At low loads during gas operation, DLN cannot be used as it leads to unstable combustion, so the combustor must operate in diffusion mode. Therefore, DLN burners are considered technically infeasible when combusting FO and when operating at low loads on NG.

[75] U.S. EPA, Clean Air Technology Center*, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR)*, EPA-452/F-03-031.

7.3.3.2 Water or Steam Injection Feasibility

Water or steam injection is a NO_X reduction technology that is commonly used to control NO_X emissions when FO is burned, but is not as effective as DLN when firing NG.[76] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[77] As the proposed turbines will utilize DLN combustors during NG operation that reduce NO_X emissions further than water or steam injection would, water or steam injection is deemed to be technically infeasible when combusting NG.

Water or steam injection is technically feasible for FO combustion and the proposed combustion turbines will have the capability to inject water or steam as part of the combustor design. Water or steam injection technology is included in the following BACT steps but represents part of the base case for NO_X performance as it is inherent in the operation of the combustion system.

7.3.3.3 Good Combustion Practices Feasibility

Good combustion practices are technically feasible. The proposed combustion turbines will be equipped with automated computer-based control systems capable of adjusting operating parameters to ensure that all turbine systems, including those intended to minimize pollutant formation, operate as effectively and efficiently as possible.

7.3.3.4 EM_X™ / $SCONO_X$™ / METEOR™ Technology Feasibility

As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, NG-fired combined cycle units, but there are engineering challenges with scaling up this technology for use on large gas turbines.[78,79] Therefore, EM_X™/$SCONO_X$™ is determined to be technically infeasible.

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[80,81] A review of the RBLC database for turbines similar to the proposed units did not return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst and it does not achieve greater reduction than SCR, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

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[76] Ibid., Attachment B page 12.

[77] Ibid.

[78] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[79] National Energy Technology Laboratory, *8.7. Nitrogen Oxides (NO_x) Emissions*. Available online at https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/nitrogen-oxides. Accessed August 15, 2024.

[80] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 16.

[81] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

7.3.3.5 SCR Feasibility

The optimal catalyst temperature for the operation of SCR is in the range of 480°F to 800°F, but with recent advances in catalyst materials and design, the temperature can be as high as 1,100°F.[82] SCR is regularly used on combined cycle units, since the exhaust from combined cycle operations has had heat removed, and the normal temperature is within the effective range for SCR.

The fuel used in the combustion turbine also impacts the effectiveness of SCR. When operating on FO, rather than NG, the emissions profile from the turbine, as well as the performance of the SCR system, are impacted. Namely, the efficiency of the SCR system is reduced, while at the same time, NO_X emissions from the turbine are increased. Nevertheless, properly designed SCR systems are capable of operating during both NG and FO operation. Thus, SCR is technically feasible for the proposed combustion turbine during both NG and FO operation.

7.3.3.6 SNCR Feasibility

The temperature range required for effective operation of this technology is 1,600 to 2,000°F. This is above the peak exhaust temperature for the proposed CCGT.[83] SNCR is eliminated as a technically feasible option for control of NO_X emissions from the combustion turbines.

7.3.4 Rank of Remaining Control Technologies (Step 3)

The potentially feasible control technologies include SCR, DLN combustors (NG operation), water or steam injection (FO operation) and good combustion practices. **Table 7-7** shows the rank for each of these control technologies.

Table 7-7. Rank Remaining NO_X Control Technologies for CTs

Control Technology	Technically Feasible	Estimated Efficiency
SCR	Yes	~90%
DLN Combustion Technology	Yes (NG only)	CT Design (NG)
Water or Steam Injection	Yes (FO only)	CT Design (FO)
Good Combustion Practice	Yes	Reduction Varies

7.3.5 Evaluation of Most Stringent Control Technologies (Step 4)

SCR is the highest ranking potentially feasible control technology. As summarized in Step 5, EKPC is proposing use of SCR with DLN and good combustion practices as BACT during NG operation (as feasible for operating load), and SCR with water or steam injection and good combustion practices as BACT during FO operation. No additional evaluation of emission control is needed.

[82] Mitsubishi Hitachi Power Systems, *Overview of SCR Technology and Retrofitting of SCR's to Comply with Upcoming NO_X BARCT Standards for Electric Power Generating Units*, Robert McGinty, presentation for SCAQMD AWMA Annual Regional Meeting, ca. 2017.

[83] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031.

7.3.6 Selection of BACT (Step 5)

7.3.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

As detailed in Section 5 of this application, the proposed CCGT will be subject to NSPS Subpart KKKK, which includes a NO_X emission standard of 15 ppm at 15% O_2 as a 4-hour rolling average (excluding startup and shutdown) during NG combustion, and a limit of 42 ppm at 15% O_2 as a 4-hour rolling average (excluding startup and shutdown) when combusting fuels other than NG. The NSPS Subpart KKKK limits serve as the floor for the allowable NO_X BACT limit.[84]

7.3.6.2 Summary of RBLC Review

EKPC queried the RBLC database using the previously specified criteria. Note that there are no RBLC entries for comparable turbines with emission limits lower than EKPC's proposed BACT limits. Detailed RBLC search results tables are provided in **Appendix D-1**.

7.3.6.3 NO_X BACT Limit Selection – Steady-State Operation

Proposed Natural Gas Steady-State NO_X BACT Limit
EKPC is proposing BACT for the CTs firing NG as the use of SCR technology, DLN, and good combustion practices. As mentioned, DLN will be used as feasible depending on turbine load. EKPC is proposing a BACT limit for NO_X of 2.0 ppmvd, corrected to 15% O_2, applied as a 30-day rolling average, excluding periods of SU/SD and FO operation (see Section 7.7 for SU/SD BACT proposal). Compliance will be demonstrated via CEMS. There are over 70 entries in the RBLC database with a 2.0 ppmvd BACT limit; therefore, the proposed limit is consistent with recent BACT determinations.

Proposed Fuel Oil Steady-State NO_X BACT Limit
EKPC is proposing BACT for the CTs firing FO as the use of SCR technology, water injection, and good combustion practices. EKPC is proposing a BACT limit for NO_X during FO operations of 4.5 ppmvd, corrected to 15% O_2 excluding periods of SU/SD and NG operation (see Section 7.7 for SU/SD BACT proposal). This limit is based on the use of water or steam injection, SCR, and good combustion practices. EKPC is proposing that the limit apply as a 30-day rolling average. Compliance will be demonstrated via CEMS.

7.4 $PM/PM_{10}/PM_{2.5}$ BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for particulate matter emissions from the CTs. Air pollution control strategies are evaluated using the top-down BACT approach. Highly efficient CTs, such as the one proposed for the CCGT EGU Project inherently emit low levels of particulate matter without add-on control devices. The underlying design includes the use of low sulfur fuels and inlet filters along with good combustion practices to mitigate particulate matter emissions from NG- and FO-firing in each CT.

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[84] EPA proposed NSPS Subpart KKKKa and revisions to NSPS Subpart KKKK on November 22, 2024. If these rules are finalized prior to start of operation, EKPC will ensure that the BACT limits are less than or equal to the applicable NSPS limits, which set the BACT floor for these units.

7.4.1 Background on Pollutant Formation

$PM/PM_{10}/PM_{2.5}$ emissions from gas combustion result primarily from incomplete combustion and also ash and sulfur in the fuel.[85] Combustion of NG and FO generates low PM emissions in comparison to other fuels due to the low ash and sulfur contents of these fuels. Regardless of the type of fuel combusted, filterable PM generally includes airborne PM which passes through the inlet air filters, inert solids in the fuel supply, and metallic rust or oxidation products.[86] The SCR system also generates $PM/PM_{10}/PM_{2.5}$ emissions, including ammonium bisulfate, ammonium sulfate, and secondary formation due to ammonia slip.

7.4.2 Identification of Potential Control Technologies (Step 1)

Table 7-8 lists the controls that reduce $PM/PM_{10}/PM_{2.5}$ from CTs.

Table 7-8. Potential $PM/PM_{10}/PM_{2.5}$ Control Technologies for CTs

Pollutant	Control Technologies
$PM/PM_{10}/PM_{2.5}$	Multicyclone Wet Scrubber Electrostatic Precipitator Baghouse Inlet Air Filters Low Sulfur Fuel Good Combustion Practices

Multicyclones, wet scrubbers, ESPs, and baghouses are all available control technologies for the reduction of $PM/PM_{10}/PM_{2.5}$. However, none of these technologies have ever been installed on a commercial combustion turbine. Therefore, these technologies will not be evaluated further in the BACT analyses.

7.4.2.1 Inlet Air Filters

Inlet air filters reduce the amount of solid particulate matter entering the turbine combustion chamber. Given that a portion of the $PM/PM_{10}/PM_{2.5}$ emissions from the turbine are generated from solids entrained in the combustion air, the use of inlet air filters can reduce $PM/PM_{10}/PM_{2.5}$. As inlet air filters are standard equipment for combustion turbines, the use of inlet air filters is considered part of the base case for the CCGT.

7.4.2.2 Low Sulfur Fuels

Combusting pipeline-quality NG or ULSFO with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form solid sulfates and other sulfur byproducts.

[85] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000.

[86] Wien S, Beres J, Richani B, General Electric Company. *Air Emissions Terms, Definitions and General Information.*; 2005. https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-4249-air-emissions-terms-definitions-general-information.pdf

7.4.2.3 Good Combustion and Operating Practices

Good combustion and operating practices (GCOP) will minimize the formation of $PM/PM_{10}/PM_{2.5}$ emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

7.4.3 Elimination of Technically Infeasible Control Options (Step 2)

The remaining control options (inlet air filters, low sulfur fuels, and good combustion practices) are technically feasible for the CCGT and are evaluated further in the BACT analysis.

7.4.4 Rank of Remaining Control Technologies (Step 3)

Of the control technologies available for $PM/PM_{10}/PM_{2.5}$ emissions, the technically feasible options for the CTs are shown in **Table 7-9**.

Table 7-9. Rank Remaining Particulate Matter Control Technologies for CTs

Control Technology	Technically Feasible for Combustion Turbine	Estimated Efficiency
Inlet Air Filters	Yes	Reduction Varies
Low Sulfur Fuel	Yes	Reduction Varies
Good Combustion and Operating Practices	Yes	Reduction Varies

7.4.5 Evaluation of Most Stringent Control Technologies (Step 4)

Good combustion and operating practices with NG and low sulfur fuel, along with inlet air filters, are the most stringent $PM/PM_{10}/PM_{2.5}$ controls that are technically feasible options. EKPC is proposing to use low-sulfur fuels, inlet air filters, and good combustion practices, as the most effective means for reducing $PM/PM_{10}/PM_{2.5}$ emissions from each CT.

7.4.6 Selection of BACT (Step 5)

7.4.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The proposed CTs are not subject to any NSPS or NESHAP rule which limit PM emissions; therefore, there is no floor for the allowable BACT limit for PM. Each CT will also not be subject to any PM emission limit under Title 401 of the Kentucky Administrative Rules.

7.4.6.2 Summary of RBLC Review

EPA's RBLC database was reviewed to determine what has been established as a BACT emission requirement for comparable operations. **Table 7-10** includes RBLC search results that are more stringent than the proposed limit for natural gas in Step 5 (equivalent to 0.006 lb/MMBtu). There are three FO entries in the RBLC database that met the criteria for inclusion in the RBLC search for the proposed project, and the proposed particulate BACT limits for the three entries are greater than the proposed fuel oil limit (equivalent to 0.012 lb/MMBtu). Therefore, there are no RBLC search results that are more stringent than the proposed limit for fuel oil. Detailed RBLC search results are presented in **Appendix D.**

Table 7-10. Particulate Matter RBLC Entries for Natural Gas-Fired CTs

RBLC ID	Facility	Permit Date	Permitted PM Limit	Units	Averaging Period
VA-0325	Greensville Power Station	6/17/2016	0.003	lb/MMBtu	N/A (stack test)
OH-0375	Long Ridge Energy Generation LLC – Hannibal Power	11/7/2017	0.0036	lb/MMBtu	Not indicated
VA-0335	Panda Stonewall, LLC	12/18/2020	0.0037	lb/MMBtu	3 Hour
OH-0363	NTE Ohio, LLC	11/5/2014	0.0038	lb/MMBtu	Not indicated
PA-0306	Westmoreland Generating Facility	2/12/2016	0.0039	lb/MMBtu (w/DB)	Not indicated
AL-0328	Alabama Power Company Plant Barry	11/9/2020	0.004	lb/MMBtu	3 Hour
IL-0130	Jackson Energy Center	12/31/2018	0.0042	lb/MMBtu	3 Hour
CT-0161	Lake Road Energy Center	6/30/2017	0.0044	lb/MMBtu	Not indicated
NY-0103	Cricket Valley Energy Center	2/3/2016	0.005	lb/MMBtu	1 Hour

In addition to the more stringent emission limits above, there are also over 20 approved limits for NG in **Appendix D** that are equivalent to or greater than the NG limit proposed for Cooper Station. Since particulate emissions from NG combustion are partially driven by the sulfur and ash content of the natural gas, variability in natural gas emission limits is expected based on the composition of the available fuel.

7.4.6.3 PM/PM_{10}/$PM_{2.5}$ BACT Limit Selection

Proposed Natural Gas PM/PM_{10}/$PM_{2.5}$ BACT Limit

EKPC is proposing a BACT limit of 17.21 lb/hr for PM/PM_{10}/$PM_{2.5}$ during NG operation, equivalent to 0.006 lb/MMBtu at 100% load, including startup and shutdown. EKPC is proposing that compliance be demonstrated using performance testing. EKPC will use pipeline-quality NG containing a maximum sulfur content of 0.5 gr S/100 scf to lower the emissions of PM/PM_{10}/$PM_{2.5}$. The proposed BACT limit is based on the vendor guarantee provided, given the composition of the available natural gas for the project.

Proposed Fuel Oil PM/PM_{10}/$PM_{2.5}$ BACT Limit

EKPC is proposing a BACT limit of 30.12 lb/hr for PM/PM_{10}/$PM_{2.5}$ during FO operation, equivalent to 0.012 lb/MMBtu at 100% load, including startup and shutdown. EKPC is proposing that compliance be demonstrated using performance testing. The proposed BACT limit is based on the vendor guarantee provided for ULSFO combustion. EKPC will use distillate FO containing no more than 15 ppm sulfur to lower the emissions of PM/PM_{10}/$PM_{2.5}$. The proposed BACT limit is based on the vendor guarantee provided, given the composition of the distillate FO for the project.

7.5 H_2SO_4 BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for H_2SO_4 emissions from each CT. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of low sulfur fuels to mitigate H_2SO_4 emissions from NG- and FO-firing in each CT.

7.5.1 Background on Pollutant Formation

H_2SO_4 emissions result from the reaction of SO_3, formed from the oxidation of SO_2 emissions, with water. Uncontrolled H_2SO_4 emissions depend on the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are primarily dependent on the sulfur content of the fuel.

7.5.2 Identification of Potential Control Technologies (Step 1)

The available control options identified for H_2SO_4 are listed in **Table 7-11**.

Table 7-11. Potential H_2SO_4 Control Technologies for CTs

Pollutant	Control Technologies
H_2SO_4	FGD Scrubber Dry Sorbent Injection Low-Sulfur Fuel Good Combustion Practices

Flue Gas Desulfurization scrubbers and Dry Sorbent Injection are both available control technologies for the reduction of H_2SO_4 emissions. However, none of these technologies have ever been installed on a commercial combustion turbine. Therefore, these technologies will not be evaluated further in the BACT analyses.

7.5.2.1 Low-Sulfur Fuel

The use of low sulfur fuels in the CCCTs decreases the amount of sulfur in the system which ultimately decreases emissions of sulfur compounds including SO_2, SO_3 and H_2SO_4 mist. EKPC will use pipeline-quality NG containing a maximum sulfur content of 0.5 gr S/100 scf and ULSFO for the fuel oil.

7.5.2.2 Good Combustion Practices

Operation and maintenance of the equipment in accordance with good air pollution control practices and with good combustion practices results in efficient combustion of fuel, which in turn results in reduced usage of fuel and associated emissions of H_2SO_4 mist.

7.5.3 Elimination of Technically Infeasible Control Options (Step 2)

Add-on controls are not available for the reduction of H_2SO_4 emissions from the CCGT. The use of low-sulfur fuels and good combustion practices are technically feasible.

7.5.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are the use of low-sulfur fuel and good combustion practices, the base case for BACT.

7.5.5 Evaluation of Most Stringent Control Technologies (Step 4)

EKPC will implement both low sulfur fuels and good combustion practices to reduce H_2SO_4 emissions from the generating units.

7.5.6 Selection of BACT (Step 5)

7.5.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The proposed generating units are not subject to any NSPS or NESHAP standard for H_2SO_4, and thus there is no floor of allowable H_2SO_4 BACT limits. Each CT will also not be subject to any H_2SO_4 emission limit under Title 401 of the Kentucky Administrative Rules.

7.5.6.2 Summary of RBLC Review

Based on review of the RBLC search results (**Appendix D-1**) and recently issued permits for similar sized power plants, the sulfur content, the primary driver for H_2SO_4 formation, ranges from 0.1 to 5 gr S/100 scf NG, with separate limits for varying averaging periods. In addition, as shown in **Appendix D-1**, the RBLC data search shows that no add-on controls are required for NG- or FO-fired CCGT generating units to control H_2SO_4 emissions. For those facilities with lower accepted NG sulfur content limitations as basis for H_2SO_4 BACT limits, the sulfur content and associated BACT limits are a function of the available natural gas supply.

7.5.6.3 Proposed H_2SO_4 BACT Limit

EKPC proposes the use of low-sulfur fuels and good combustion practices as BACT for H_2SO_4 emissions. NG combusted in the CCGT will contain no more than 0.5 gr S/100 scf, and FO combusted will contain no more than 15 ppm total sulfur. The site-specific NG sulfur content for the Cooper Project is based on pipeline data for the area from candidate NG suppliers.

7.6 GHG BACT Evaluation

This section contains a high-level review of pollutant formation and possible control technologies for the CT systems. The vast majority of GHG emissions, on a CO_2e, from combustion turbines are CO_2. Emissions of CH_4 from turbines are typically extremely low.[87] CH_4 can be emitted when a fossil fuel is not burned completely in combustion.[88] The last primary component for calculating GHG emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete gas combustion, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[89] N_2O emissions in the turbine exhaust are generally less than 1 ppm during startup, potentially rising to several ppm during transient operation, which is insignificant compared to the CO_2 emissions from the turbine, even on a CO_2e basis. Therefore, given that CO_2e emissions from the turbine are made up of almost entirely CO_2, EKPC is presenting a GHG BACT analysis focused on CO_2.

[87] *White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units, April 21, 2022.* Prepared by U.S. EPA. Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Combustion Turbine Electric Generating Units

[88] AP-42, Chapter 1, Section 4, *Natural Gas Combustion.* July 1998.

[89] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

7.6.1 Background on Pollutant Formation

CO_2 production from combustion occurs by a reaction between carbon and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted assuming complete combustion occurs).[90]

7.6.2 Identification of Potential Control Technologies (Step 1)

EKPC reviewed the large body of information on GHG emissions from combustion turbines compiled from various rulemakings, such as the NSPS Subpart TTTT and TTTTa preambles. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are included in **Appendix D**, detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHG have been deemed BACT for any facility. Many of the RBLC entries list a variant of good combustion practices, efficient operation, state-of-the-art technology, or low emitting fuels (e.g., pipeline-quality NG and ULSFO). EKPC has selected NG as the primary fuel for the CCGTs which is the lowest GHG emitting fuel available for the Cooper Project. With NG selected as a low carbon fuel as the base case design basis for the CCGTs, this control option is not evaluated further in the remaining steps of the GHG BACT analysis for CCGTs because the GHG emissions reduction potential from using NG as a low carbon fuel is already included in the GHG emissions basis.

Table 7-12 lists potential CO_2 control strategies that were considered as part of this BACT analysis.

Table 7-12. Potential GHG Control Technologies for CTs

Pollutant	Control Technologies
GHG	CCS Efficient CCGT Operation and Good Combustion Practices

These control technologies are discussed in the following sections.

7.6.2.1 Carbon Capture and Sequestration/Storage

CCS involves (1) "capturing" and separating the CO_2 from the exhaust of the emission source; (2) transferring the CO_2 to an appropriate injection site; **and** (3) sequestering/storing the CO_2 at a suitable site.

The first phase in CCS is to separate and capture the CO_2 gas from the exhaust stream, and then to compress the CO_2 to a supercritical condition.[91] Since most storage locations for CO_2 are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for CO_2, to inject CO_2 to those depths requires pressurizing the captured CO_2 to a supercritical state.

CO_2 capture can be performed via four main methods: absorption, adsorption, membranes, and cryogenic separation. The choice of the precise process varies with the properties of the exhaust stream. CO_2

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[90] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[91] Supercritical means that the CO_2 has properties of both a liquid and a gas. Supercritical CO_2 is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a CT system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated CO_2 than exhaust from NG combustion, or on NG/FO combined cycle systems.

Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. The CO_2 could be compressed to supercritical either before or after transport. The technology needed to compress CO_2 to supercritical conditions is available; however, specialized technologies require high operating energy requirements. It is important to understand that there are technical challenges with compressing the expected volume of CO_2 generated from both CTs (or both CTs **and** the C2 co-firing operation). To do this step, EKPC would be required to co-locate a new chemical manufacturing facility.

For phase two, CO_2 would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO_2 pipelines, particularly if supercritical CO_2 is being transported. Transport of CO_2 by pipeline is a demonstrated technology, but currently most CO_2 pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various CO_2 storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting CO_2 into deep subsurface formations for permanent storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO_2 could also potentially be used for enhanced oil recovery via injection into oil fields.

7.6.2.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine design and good combustion, operating, and maintenance practices.

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work. Maintaining the combustion units is important for efficient operation.

7.6.3 Elimination of Technically Infeasible Control Options (Step 2)

7.6.3.1 Carbon Capture, Transport, and Storage

CCS involves cooling, separation and capture of CO_2 from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

Carbon Capture

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[92] Currently, only two options appear to be feasible for capture of CO_2 from the flue gas from the turbine systems:

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[92] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[93]

A review of the U.S. Department of Energy's (DoE) National Energy Technology Laboratory's (NETL) research and development awards related to post-combustion capture of CO_2 indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus; however, the existence of several Front End Engineering Design (FEED) studies indicates that commercial implementation is beginning to move forward.[94] For example, a FEED study is underway for a commercial-scale carbon capture facility retrofitted at the Delta Energy Center in Pittsburg, CA, capable of capturing 2.4MM tons of CO_2 per year.[95]

Another pilot-scale study is underway for a 1.7 MM ton/yr CO_2 capture project at Louisville Gas and Electric Kentucky Utilities Cane Run #7.[96] That project is planned to study methods for collecting CO_2 from the flue gas stream; however, there are no plans to "transport" in the traditional pipeline sense. The plan is to see if some of the captured CO_2 can be made commercial grade and potentially sold to interested parties. If none are available, the slip stream would be re-released.

Although FEED studies indicate heightened interest in exploring potential implementation opportunities for CCS, EKPC is aware of only one successful CCS deployment on a combined cycle combustion turbine facility. The Bellingham Energy Center captured CO_2 from a slipstream (i.e., a portion of the turbine exhaust stream) for use in the food industry and operated from 1991 to 2005.[97] Additionally, a planned 2,000 MW NG combined cycle power plant with CCS is expected to come online towards the end of the 2020s, but construction is not expected to start for several years at least.[98]

Presuming carbon capture is feasible, prior to sending the CO_2 stream to the appropriate storage site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[99] The auxiliary power load could be handled by installation of a separate system to solely support CO_2 compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power

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[93] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[94] Website reviewed June 2024: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[95] *Front-End Engineering Design for a CO_2 Capture System at Calpine's Delta Energy Center,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032149, start date February 1, 2022.

[96] *CO_2 Capture at Louisville Gas & Electric Cane Run Natural Gas Combined Cycle Power Plant,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032223, start date December 22, 2022. https://netl.doe.gov/sites/default/files/netl-file/24CM/24CM_PSCC_5_Berger.pdf

[97] *Greenhouse Gas Mitigation Measures: Carbon Capture and Storage for Combustion Turbines Technical Support Document,* U.S. Environmental Protection Agency, Office of Air and Radiation, May 23, 2023. (pp. 23)

[98] *Company Responds as PSC green lights siting for future plant in Doddridge County*, West Virginia Metro News, May 5, 2024. https://wvmetronews.com/2024/05/05/psc-green-lights-siting-certificate-for-cpvs-future-plant-in-doddridge-county/

[99] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

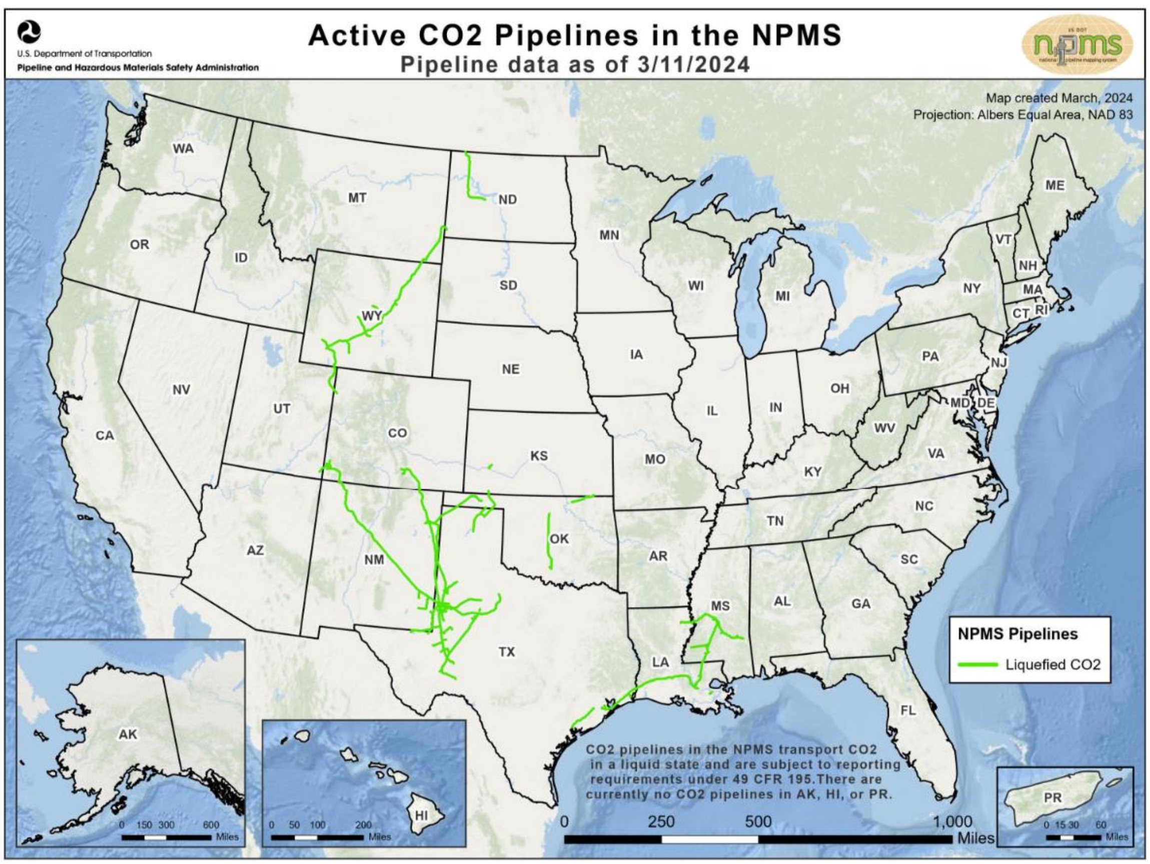
needs of the compression system. This is often referred to as an "energy penalty" for operation of the CO_2 compression system, and in effect can reduce the net CO_2 reduction of the CCS system.

Carbon Transport

The next step in CCS is the transport of the captured and compressed CO_2 to a suitable location for storage. This would typically be via pipeline. Pipeline transport is an available and demonstrated, although costly, technology. Short CO_2 pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

Since there are no other CO_2 pipelines in the area, as shown in Figure 7-1, EKPC would need to construct a CO_2 pipeline to a storage location if it were to pursue carbon sequestration as a CO_2 control option.[100] While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. For the purposes of this technical feasibility analysis, it is conservatively assumed that a shortest distance pipeline (~350 miles) can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

Figure 7-1. NPMS Active CO_2 Pipelines



[100] *Active CO_2 Pipelines in the NPMS,* U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration National Pipeline Mapping System, March 11, 2024. https://www.npms.phmsa.dot.gov/Documents/NPMS_CO2_Pipelines_Map.pdf

Carbon Storage
Capture of the CO_2 stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rock
- Un-Mineable Coal Seams: Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for EKPC to permanently store the captured CO_2.

NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[101] According to the database, the nearest potential sequestration sites where test wells were drilled are the Sugar Creek Field and the Western Kentucky CO_2 Test well. Both sites are more than 100 miles away from the proposed CCGT location.

Elimination of CCS as Technically Feasible
EKPC has concluded that CCS technology is not technically feasible at this time, based on the following key considerations:
- Solvent-based carbon capture systems have not been demonstrated for a large combined cycle combustion turbine;
- There are no existing or planned CO_2 pipelines within a reasonable distance from the proposed project; and
- There are no existing or planned commercially available sequestration sites within a reasonable distance from the proposed project.

7.6.3.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are

[101] Carbon Capture and Storage Database maintained by the NETL, accessed July 2021 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

Therefore, efficient turbine operation coupled with good combustion, operating, and maintenance practices is evaluated further for CO_2 BACT purposes.

7.6.4 Rank of Remaining Control Technologies (Step 3)

Efficient turbine operation and good combustion, operating, and maintenance practices is the only remaining control method. Reduction efficiency is not applicable for this control method.

7.6.5 Evaluation of Most Stringent Control Technologies (Step 4)

EKPC will implement efficient turbine operation and good combustion, operating, and maintenance practices.

7.6.6 Selection of BACT (Step 5)

7.6.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

As summarized in detail Section 5.1.10 of this application, the proposed CCGT will be subject to Subpart TTTTa. The NSPS includes CO_2 emission limits for CTs, based on the annual capacity factor of the turbines, where capacity factor in this case means net electric sales as a percentage of potential electric output. The CO_2 emission limits are as follows:

- Base load CT:
  - Phase 1 (prior to January 2032): 800 to 1,120 lb CO_2/MWh-g energy output,[102] based on combined cycle operation
  - Phase 2 (after December 2031): 100 to 150 lb CO_2/MWh-g energy output, as determined by 40 CFR §63.5525a, based on CCS
- Intermediate load CT:
  - 1,170 - 1560 lb CO_2/MWh-g energy output, as determined by 40 CFR §63.5525a, based on highly efficient simple-cycle generation
- EKPC must operate and maintain each CT, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of your EGU. [40 CFR §60.5525a(b)]

[102] In accordance with 40 CFR 60.5520a(c), the emission limits should be based on gross energy output unless the owner or operator of a stationary combustion turbine petitions the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard.

7.6.6.2 Summary of RBLC Review

EKPC queried the RBLC database using the previously mentioned criteria. Detailed RBLC search results are presented in **Appendix D-1**.

From the detailed RBLC search results, EKPC conducted additional research into individual entries to identify units which have been built and are currently operational. **Table 7-13** below presents the results of this research, and includes units with CO_2 limits lower than the proposed BACT limit of 800 lb/MWh when firing NG.

Table 7-13. CO_2 RBLC Entries for Operating NG Combined Cycle Turbines

RBLC ID	Facility	Process	Permit Date	Permitted CO_2 Limit	Units	Averaging Period
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	775	lb/MWh	12-mo Rolling
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	794	lb/MWh	12-mo Rolling

BACT determinations for similar combined cycle generating units denote energy efficiency, good design and good combustion practices as BACT. Post-combustion capture and sequestration of CO_2 is not required. CO_2 BACT limits for turbine units can be found expressed in terms of lb/MMBtu, lb/MWh-n, lb/MWh-g, Btu/kWh, lb/hr, or tons, typically with a 12-month rolling averaging period.

7.6.6.3 CO_2 BACT Limit Selection

EKPC acknowledges that a BACT limit must be at least as stringent as the most stringent applicable Part 60, 61, or 63 regulation or state regulation. As previously discussed, Units 3 and 4 are subject to Subpart TTTTa. However, multiple petitioners are challenging the legality of Subpart TTTTa, in a lawsuit which is pending at the time of submittal of this Application. Given the potential that Subpart TTTTa could be vacated by the Court in whole or in part, remanded to EPA for revisions, or otherwise repealed prior to the issuance of the permit at issue, the overall applicability of Subpart TTTTa and/or its regulatory requirements and timelines could change. If that occurs, EKPC will coordinate with the Division to revise this Application as necessary to conform to the regulatory status of Subpart TTTTa. In the event NSPS Subpart TTTTa is not overturned, EKPC will comply with the applicable emission limits under Subpart TTTTa, which sets the BACT floor. In the meantime, EKPC proposes an alternative BACT based on the top-down analysis presented above in the event that Subpart TTTTa is not an applicable federal regulation at the time of permit issuance.

Based on the top-down BACT analysis, carbon capture is not technically feasible for the reasons described in Step 2 above. The only technically feasible control option is efficient turbine operation and good combustion, operating, and maintenance practices.

BACT limits, as represented in the RBLC, are generally in the range of 750 lb/MWh-gross to 1,000 lb/MWh-gross for NG operation. The two output-based CO_2 RBLC entries for combined cycle units firing FO are near 1,200 lb/MWh. It should be noted that there exists a high degree of variability between individual sites with respect to realized turbine efficiency due to many factors, including altitude, climate, fuel properties, duct burners, turbine make and model, etc. EKPC is proposing the BACT limits below based on performance information provided by the vendor, which is specific to the proposed F-class CCGTs at Cooper. Thus, while slightly lower limits have been determined as BACT for other CCGT projects, these units are larger class, and the limits may not be achievable in practice for F-class CCGTs.

Proposed CO_2 BACT Limit – Combined Cycle (Natural Gas)
EKPC is proposing BACT for CO_2 for the combined cycle combustion turbine as efficient turbine operation and good combustion, operating, and maintenance practices to achieve a BACT emission limit of 800 lb/MWh-gross, demonstrated on a 12-month rolling basis. EKPC is proposing that this limit apply only during natural gas operation. The compliance demonstration methodology for the CO_2 BACT limit will be in accordance with 40 CFR Part 75.

Proposed CO_2 BACT Limit – Combined Cycle (Fuel Oil)
EKPC is proposing BACT for CO_2 for the combined cycle combustion turbine as efficient turbine operation and good combustion, operating, and maintenance practices to achieve a BACT emission limit of 1,250 lb/MWh-gross, demonstrated on a 12-month rolling basis. EKPC is proposing that this limit apply only during fuel oil operation. The compliance demonstration methodology for the CO_2 BACT limit will be in accordance with 40 CFR Part 75.

7.7 CCGT SU/SD BACT

As indicated for some of the pollutants in the preceding sections, the BACT limits for steady-state operation are not appropriate during startup and shutdown periods for the CCGT. Separate BACT limits are necessary given that add-on control devices are not operating at design conditions when the CCGT starts up and need time to reach operating conditions that allow for steady-state control performance. The amount of time it takes for each add-on control device to reach steady-state operating conditions exceeds the amount of time it takes the CCGT to reach its operating load. Below MECL, pollutant emissions performance during a shutdown cannot be maintained at the same level as during steady-state operation. Accordingly, EKPC requests separate emission limits for pollutants affected by add-on controls (CO, VOC, and NO_X) during the time from the initial startup of the CCGT until add-on controls reach steady-state operating conditions. **Table 7-14** below provides the proposed secondary BACT limits for CO, VOC, and NO_X, which include emissions from normal operation and SU/SD. Refer to Section 3.1 for more information on how these annual emissions-based BACT limits were derived.

Table 7-14. Proposed Annual BACT Limits Including SU/SD

Pollutant	BACT Limit for Each Turbine (tpy)
NO_X	165
CO	2,390
VOC	226

For pollutants other than CO, VOC, and NO_X, potential emissions from steady-state operation are higher than from SU/SD, therefore no secondary BACT limits are needed.

8. BACT ANALYSIS FOR CO-FIRED C2 BOILER

The proposed C2 boiler will be capable of firing 100% coal and 100% NG and co-firing NG and coal. The C2 Boiler BACT analysis described herein only applies to the co-firing NG and 100% NG operations proposed for C2. As discussed in Section 6.2.1, one source of data used in the BACT analysis is the RBLC database. **Appendix D** provides a listing of the recent BACT determinations for utility boilers pulled from the RBLC database to both identify available control technologies and achievable emissions levels for the various control options.

EKPC queried the RBLC database to identify BACT limits for similar coal boilers to the modified C2 unit using the following criteria:

- Process Type Code:
  - 11.000 (Utility and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr))
  - 11.100 (Solid Fuel & Solid Fuel Mixtures (> 250 MMBtu/hr))
  - 11.110 (Coal (includes bituminous, subbituminous, anthracite, and lignite))
- RBLC Search Date = October 17, 2024
- RBLC Search Criteria = Permit Date 1/1/04 to Present
- RBLC Search Criteria = Process Type - 11.110
- Sort Order = Permit Issuance Date Newest to Oldest
- Include/Exclude Criteria =
  - Filter by Process Type - 11.11
  - Preliminary Permit Issuance Date Prior to 1/1/06

EKPC then queried the RBLC database using the following additional criteria to identify NG boilers with GHG BACT limits:

- Process Type Code:
  - 11.300 (Gaseous Fuel & Gaseous Fuel Mixtures (> 250 MMBtu/hr)
  - 11.310 (NG, includes propane and LPG)
- RBLC Search Date = November 5, 2024
- RBLC Search Criteria = Permit Date 1/1/04 to Present
- RBLC Search Criteria = Process Type - 11.310
- Sort Order = Permit Issuance Date Newest to Oldest
- Include/Exclude Criteria =
  - Filter by Process Type - 11.31
  - Filter out any entries w/ Primary Fuel as Non-NG
  - Filter by Throughput Unit of MMBtu/hr and value >= 1,000 MMBtu/hr
  - Filter out any SIC code 4911 as duplicative of first tab

For the sake of brevity, EKPC removed entries for units with a maximum capacity of less than 1,000 MMBtu/hr.

These "generic" RBLC search results have been further screened to exclude units that are not representative of the proposed co-fired C2 Boiler. These additional screening criteria further documented in Step 5 of each pollutant-specific BACT analysis include: 1) proposed new EGU boilers which have not been constructed and thus have not demonstrated compliance with any proposed BACT limits, and 2) boilers that are not comparable to the C2 boiler due to pollutant-specific unit design and operating considerations including fuel types, thermal cycles, and boiler technology.

With respect to the level of the BACT limit, EKPC has only evaluated sources with more stringent (i.e., lower) permitted emissions limits in Step 5. As such, those units with equivalent or higher permitted emissions limits are not represented in the pollutant-specific RBLC summary tables in the following subsections. Information on those units with equivalent or higher emissions limits are included in the full RBLC tables within **Appendix D**.

8.1 CO and VOC BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for CO and VOC emissions from the co-firing operations proposed for C2. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of good combustion and operating practices to mitigate CO and VOC emissions from the C2 boiler while firing NG.

8.1.1 Background on Pollutant Formation

Similar to CO and VOC from the CCGT, CO and VOC from the co-fired utility boiler are a by-product of incomplete combustion. Ensuring sufficient oxygen supply, fuel/air mixing, combustion temperature, and residence time ensures complete combustion and reduction in CO and VOC emissions. Trace amounts of VOCs in NG (e.g., benzene) also contribute to VOC emissions if they are not completely combusted in the boiler. Ensuring sufficient oxygen supply, fuel/air mixing, combustion temperature, and residence time ensures complete combustion and a reduction in CO and VOC emissions.

8.1.2 Identification of Potential Control Technologies (Step 1)

Potentially applicable CO and VOC control technologies for utility boilers were identified using the RBLC search and review of technical literature as shown in **Table 8-1**.

Table 8-1. Potential CO and VOC Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies
CO and VOC	Thermal Oxidation Oxidation Catalyst Good Combustion Controls

8.1.2.1 Thermal Oxidation

A thermal oxidizer supplies sufficient combustion air and supplemental fuel at a suitable temperature (around 1,500 ^{o}F) to allow for oxidation of VOC and other combustible compounds (including CO) present in the exhaust stream within the combustion chamber.

8.1.2.2 Oxidation Catalyst

Oxidation catalyst control technology is discussed in detail in Section 7.1.2.1.

8.1.2.3 Good Combustion Practices

Optimizing burner design and combustion air systems results in good combustion efficiency in boilers, which reduces CO and VOC emissions. Efficient combustion depends on equipment design and operational practices. The firebox must ensure adequate residence time, temperature, and turbulence in the combustion zone, along with the proper air-to-fuel ratio to ensure low CO and VOC emissions.

8.1.3 Elimination of Technically Infeasible Control Options (Step 2)

Technical feasibility of the aforementioned controls in a co-fired utility boiler is addressed as follows.

8.1.3.1 Thermal Oxidation

Thermal oxidation systems require significant temperatures (around 1,500 ^{o}F) to oxidize the remaining combustible carbon compounds present in the stream. To prevent the need for reheating the exhaust stream, the thermal oxidizer would need to be installed prior to the existing CDS control device. As a result, significant amounts of sulfur compounds would be present in the exhaust stream during co-firing.

Thermal oxidation would reduce CO and VOC emissions, but would also oxidize the sulfur compounds creating more SO_3 that can react with water to form additional H_2SO_4 mist. This mist can damage downstream pollution control equipment. Since coal combustion will continue after the project, EKPC expects high levels of sulfur compound emissions to be present and enter the thermal oxidizer if located prior to the CDS.

If the thermal oxidation system is installed after the CDS, the exhaust stream would need to be reheated to the requisite temperature, which would require additional fuel combustion and associated increases in NO_X and CO_2 emissions.

Due to these technical challenges, thermal oxidation is a technically infeasible control strategy for CO and VOC emissions from a coal and NG co-fired utility boiler. Furthermore, this technology has not been used for EGU boilers and is therefore not demonstrated within the industry.

8.1.3.2 Oxidation Catalyst

Oxidation catalysts have several design aspects to consider. Particulate-laden streams are known to coat and deactivate the catalyst over time. Thus, the oxidation process would have to occur downstream from a PM control device to achieve effective results. Additionally, the flue gas must be within an ideal temperature range (from 600 to 800°F) in order to achieve appreciable conversion, with conversion increasing with temperature. Therefore, the flue gas stream would need to be reheated downstream from the baghouses in order to achieve a reduction in CO and VOC emissions. Reheating this stream would require additional fuel combustion and subsequent increases in NO_X and CO_2 emissions.

To prevent the need for reheating, the oxidation catalyst equipment could be installed prior to the SCR NO_X control device where the gas stream is in the required temperature range. However, installing prior to the SCR means that the oxidation catalyst is installed prior to the baghouse where the catalyst would be susceptible to plugging from the particulate emissions in the flue gas stream. Further, if installed prior to the SCR, the catalyst is also susceptible to poisoning from the metallic and sulfur compounds present in the exhaust stream. Regardless of the placement of this device, the installation of an oxidation catalyst is technically infeasible for CO and VOC control from a coal and NG co-fired boiler. Although SCR systems are technically feasible for coal-fired units, the catalyst used for CO and VOC control is different from the NO_X catalyst, allowing a smaller available area for flue gas flow and higher susceptibility to plugging and fouling. Furthermore, this technology has not been used for co-fired EGU boilers and is therefore not demonstrated within the industry.

8.1.3.3 Good Combustion Practices

Use of good combustion practices is technically feasible for the C2 boiler and is a common methodology for minimizing CO and VOC emissions from utility boilers. This represents the base case for operation of the C2 boiler.

8.1.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of CE below in **Table 8-2**.

Table 8-2. Remaining CO and VOC Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies	Potential Control Efficiency (%)
CO and VOC	Good Combustion Practices	Reduction Varies

8.1.5 Evaluation of Most Stringent Control Technologies (Step 4)

Good combustion control is the only control technology remaining of the available control technology options reviewed that has been implemented for coal and NG co-fired utility boilers and is proposed as the most effective means for reducing emissions of CO and VOC from C2's co-fired operations.

8.1.6 Selection of BACT (Step 5)

8.1.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

After the C2 Co-Firing Project, C2 still will not be subject to any NSPS or NESHAP standard for CO or VOC, and thus there is no floor for an allowable CO or VOC BACT limit. The co-fired C2 boiler will also not be subject to any CO or VOC emission limit under Title 401 of the Kentucky Administrative Rules.

8.1.6.2 Summary of RBLC Review

The RBLC database includes several NG-fired utility boilers, yet none were presented for coal and NG co-firing operation. The RBLC search results are summarized by both 100% coal and 100% NG as shown in **Appendix D**.

Summary for CO. Only one entry has a CO emission limit for a natural gas-fired utility boiler lower than the proposed emission limit of 0.12 lb/MMBtu: FG LA Complex ST. James, NG-Fired Utility Boilers 1 & 2, 1,200 MMBtu/hr ea. LA-0364 lists BACT as 0.037 lb of CO/MMBtu by use of NG or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices. The FG LA Complex (LA-0364) involves proposed new units that will be NG-only. As new units that do not involve control device retrofitting or fuel conversion, these units are not applicable to the C2 Boiler project.

Only two entries have CO emission limits for coal-fired utility boiler lower than the proposed emission limit of 0.12 lb/MMBtu: the Tenaska Trailblazer Energy Center at 0.1 lb/MMBtu, and the PacifiCorp Naughton plant Unit 3 at 0.02 lb/MMBtu. Neither facility is co-fired with natural gas, therefore, these exclusive coal-firing limits do not account for the contribution of NG combustion, which results in higher CO emissions on a lb/MMBtu basis. Additionally, the Tenaska Trailblazer Energy Center plant was not constructed, and therefore compliance with this emission limit was not demonstrated. The referenced PSD permit for the

PacifiCorp Naughton plant did not establish a 0.02 lb/MMBtu emission limit for Unit 3, and was therefore included in the RBLC in error.

The proposed CO BACT (see below) meets or exceeds the most stringent limit of similar sources as identified in the RBLC search provided in Tables D-2.2 and D-3.2 of **Appendix D**, as well as other permit searches.

Summary for VOC. The RBLC contains no VOC entries for co-fired or NG-fired utility boilers greater than 1,000 MMBtu/hr. EKPC reviewed coal entries in the RBLC database for boilers greater than 1,000 MMBtu/hr and identified entries with VOC emission limits less than the proposed limit for C2. The RBLC search results are provided in Table D-2.3 of **Appendix D**. However, as previously stated for CO, exclusive coal firing does not account for the contribution of NG combustion, which results in higher VOC emissions on a lb/MMBtu basis. Therefore, the coal-fired boiler RBLC entries do not establish BACT for the proposed C2 modification.

8.1.6.3 CO BACT Selection for Co-Fired C2 Boiler Steady-State Operation

EKPC will utilize good combustion practices to reduce CO emissions according to the requirements of BACT. Based on equipment vendor data, EKPC is proposing a BACT limit of 0.12 lb/MMBtu for CO on a 3-hour average basis during all periods of operation except startup and shutdown when firing NG alone or in combination with coal. Compliance with this limit will be demonstrated through the combustion of permitted fuels and initial stack test results. The proposed CO BACT limit for the C2 boiler would not include periods of startup and shutdown as conducting stack tests during these periods is not feasible and other work practice standard alternatives can be implemented to ensure CO emissions during startup and shutdown events are minimized in accordance with good combustion and operating practices (see Section 8.1.6.5).

8.1.6.4 VOC BACT Selection for Co-Fired C2 Boiler Steady-State Operation

EKPC will utilize good combustion practices to reduce VOC emissions according to the requirements of BACT. Based on equipment vendor data, EKPC is proposing a BACT limit of 0.0055 lb/MMBtu for VOC on a 3-hour average basis during all periods of operation except startup and shutdown when firing NG alone or in combination with coal. Compliance with this limit will be demonstrated through combustion of permitted fuels and initial stack test results. The proposed VOC BACT limit for the C2 boiler would not include periods of startup and shutdown as conducting stack tests during these periods is not feasible and other work practice standard alternatives can be implemented to ensure VOC emissions during startup and shutdown events are minimized in accordance with good combustion and operating practices (see Section 8.1.6.5).

8.1.6.5 CO and VOC BACT Selection for Co-Fired C2 Boiler Startup and Shutdown

During periods of startup and shutdown, EKPC proposes to comply with the relevant portions of the work practice standards outlined in 401 KAR 61:015 Section 9.

8.2 NO_X BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the co-firing operations proposed for C2. Air pollution control strategies are evaluated using the top-down BACT approach. An SCR is already installed and operating to control NO_X emissions from coal-firing in the C2 boiler. With the C2 Co-Firing Project, the SCR will continue to operate when firing 100% NG and co-firing NG and coal.

8.2.1 Background on Pollutant Formation

The three predominant forms of NO_X formation within a utility boiler are thermal NO_X, prompt NO_X, and fuel NO_X, which are discussed in Section 7.3.1.

Thermal and fuel NO_X account for the majority of the NO_X formed in coal- and NG-fired utility boilers; however, the relative contribution of each depends on the combustion process and fuel characteristics. NG contains negligible fuel nitrogen; therefore, the majority of the NO_X in these boilers is thermal NO_X. The major factors that influence thermal NO_X formation are temperature, concentrations of oxygen and nitrogen, and residence time. If the temperature or the concentration of oxygen or nitrogen can be reduced, thermal NO_X formation can be suppressed or quenched. Prompt NO_X, however, is formed rapidly. Thus, it is not possible to quench prompt NO_X formation as it is for thermal NO_X formation. However, the contribution of prompt NO_X to the total NO_X emissions of a system is rarely large.[103]

The oxidation of fuel-bound nitrogen (fuel NO_X) is the principal source of NO_X emissions from combustion of coal. All indications are that the oxidation of fuel bound nitrogen compounds to NO_X is rapid and occurs on a time scale comparable to the energy release reactions during combustion. The primary technique for controlling the formation of fuel NO_X is delayed mixing of fuel and air so as to promote conversion of fuel-bound nitrogen to N_2 rather than NO_X. As with prompt NO_X, fuel NO_X formation cannot be quenched as can thermal NO_X. The formation of thermal, prompt, and fuel NO_X in combustion systems is controlled by modifying the combustion gas temperature, residence time, and turbulence. Of primary importance are the localized conditions within and immediately following the flame zone where most combustion reactions occur.

As explained elsewhere, the burners in the C2 boiler are being modified such that the burners can switch back and forth between firing either coal or NG. This limits the ability to optimize the combustion gas temperature, residence time, and turbulence locally within or near the flame zones, as the optimization is different when attempting to minimize thermal NO_X during NG combustion compared to attempting to minimize fuel NO_X during coal combustion.

8.2.2 Identification of Potential Control Technologies (Step 1)

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) and/or introduce inert species (combustion products, for example) that limit initial NO_X formation. Several post-combustion NO_X control technologies are also potentially applicable to the post-project C2 boiler. These technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

The control technologies identified for NO_X are listed in the table below and discussed in more detail in the following subsections. Note that the C2 boiler is currently equipped with SCR add-on control.

[103] *Alternative Control Technologies Document NO_X Emissions from Utility Boilers*, March 1994, https://www3.epa.gov/ttn/catc/dir1/utboiler.pdf.

Table 8-3. Potential NO_X Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies
NO_X	SCR (base case) LNBs / Over-Fire Air (OFA) SNCR Rich Reagent Injection (RRI) Flue Gas Reheat Oxygen Enhanced Combustion FGR Economizer Bypass

8.2.2.1 SCR

SCR control technology is discussed in detail in Section 7.3.2.5.

8.2.2.2 LNBs / OFA

There are many different types of LNBs. In principle, however, LNBs provide a stable flame with different zones resulting in lower temperatures that mitigate NO_X. For example, separate flame zones can be used for primary combustion, fuel reburning, and final combustion with low excess air to limit the temperature. It should be noted that LNBs can result in increases of CO and VOC emissions as well as unburned carbon in the fly ash.

When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the fuel-rich mixture is always off-stoichiometric when combustion is occurring, the temperature is lower, which reduces NO_X formation. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA.

8.2.2.3 SNCR

SNCR control technology is discussed in detail in Section 7.3.2.6.

8.2.2.4 Rich Reagent Injection

RRI is a NO_X control technology originally developed for use and commercially demonstrated in coal-fired cyclone boilers, as it requires the fuel-rich environment created in the lower furnace by cyclone boilers with overfire air. Similar to SNCR, NO_X reduction is achieved in RRI by injecting reductant (e.g., urea) into the fuel-rich region of the furnace at the combustion zone. The main difference between RRI and SNCR systems is that reagent injection occurs at significantly higher gas temperatures within the combustion zone of the lower furnace (2400-3100 °F).

8.2.2.5 Flue Gas Reheat

Flue gas reheat during low load, startup and shutdown increases the flue gas temperature potentially making operation of SCR technically feasible at low load operations. This option may include installation of flue gas reheat burners or an economizer bypass—refer to the separate economizer bypass sub-section for discussion on the latter.

8.2.2.6 Oxygen Enhanced Combustion

An oxygen enhanced combustion system uses a cryogenic process to supply pure oxygen; atmospheric pressure combustion for fuel conversion in a conventional supercritical pulverized-coal boiler.

8.2.2.7 Flue Gas Recirculation

FGR is a process that takes a portion of the flue gas from the combustion process and recirculates it back into the boilers. The recirculated flue gas acts as a thermal diluent to reduce combustion temperatures and, hence, NO_X formation. It also dilutes the combustion reactants and reduces the excess air requirements thereby reducing the concentration of oxygen and nitrogen in the combustion zone, inhibiting thermal NO_X formation.[104]

8.2.2.8 Economizer Bypass

An economizer bypass could enable higher flue gas exhaust temperatures to reach the downstream SCRs. This could allow the SCRs to operate at lower load profiles.

8.2.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits.

8.2.3.1 SCR

As stated previously, an SCR is already installed and used to control NO_X for the C2 boiler.

8.2.3.2 LNBs / OFA

The existing burners are considered LNBs for coal combustion, as they are designed to mitigate fuel NO_X to the extent practical. As discussed in Section 8.2.1., the burners in the C2 boiler are being modified such that the burners can switch back and forth between firing either coal or NG. The post-project fuel flexibility limits the ability to optimize these parameters when attempting to minimize thermal NO_X during NG combustion or further mitigate fuel NO_X during coal combustion.

To achieve the required fuel flexibility, LNBs are not a feasible technology for NG combustion. The vendor offers two technologies for converting coal burners to NG burners, and only one of these technologies is capable of maintaining the flexibility to switch between coal combustion and NG combustion. This technology for the new multi-fuel burners does not meet the conventional metrics for LNB performance during NG combustion.

EKPC also explored the possibility of adding OFA to the proposed new multi-fuel burner design. However, in order to institute OFA, EKPC would have to modify the current primary and flue gas fan control methods which would represent a large-scale change in how the boiler currently operates. In addition to these feasibility issues, OFA would not provide more reduction than the existing SCR and will not be considered further.

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[104] U.S. EPA, Clean Air Technology Center. *Nitrogen Oxides (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina. p. 15, EPA-456/F-99-006R, November 1999.

8.2.3.3 SNCR

SNCR is a technically feasible control option for the C2 Boiler.

8.2.3.4 RRI

RRI is a NO_X control technology originally developed for use and commercially demonstrated in coal-fired cyclone boilers. This technology is not feasible for a wall-fired boiler.

8.2.3.5 Flue Gas Reheat

Flue gas reheat by installation of flue gas reheat burners would be impractical for large units at a coal-fired utility due to the decrease in boiler efficiency and massive increase in SCR operational costs (as much as 60% of annual maintenance and operational costs).[105]

8.2.3.6 Oxygen Enhanced Combustion

An oxygen enhanced combustion system uses a cryogenic process to supply pure oxygen; atmospheric pressure combustion for fuel conversion in a conventional supercritical pulverized-coal boiler and substantial flue gas recycle. This technology has not been demonstrated on coal-fired boilers and the C2 boiler is not a supercritical system; thus, this technology has been determined to be technically infeasible.

8.2.3.7 Flue Gas Recirculation

This technology reduces thermal NO_X and is not applied to multi-fuel boilers like the C2 boiler because NO_X emissions from coal combustion are primarily fuel NO_X (as opposed to thermal NO_X, which is mitigated by FGR). Therefore, FGR is only useful for mitigating NO_X from NG combustion. Furthermore, FGR requires the flue gas to be readmitted either into the furnace hopper or the windbox of the boiler. For boilers designed to burn coal such as the C2 boiler, the recirculated flue gas is commonly readmitted either into the furnace hopper or *above* the windbox because it is needed to control temperature in the secondary superheater and reheater—this is not used as a NO_X mitigation technique. [106] Windbox FGR would be a potential NO_X mitigation measure during NG combustion; however, it is infeasible to have FGR that is capable of operating only during certain operating scenarios during which flue gas could be readmitted to the windbox. Therefore, FGR is not technically feasible to control NO_X emissions from the C2 boiler.

8.2.3.8 Economizer Bypass

Installing a bypass of the units' economizers would fundamentally change the combustion characteristics of the boiler and would constitute a major modification of the units impacting the units' heat transfer, energy efficiency and net electrical generation. In addition, space constraints and the elevation of the economizer make an economizer bypass technically infeasible.

8.2.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of CE below in **Table 8-4**.

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[105] *Economic and Cost Analysis for Air Pollutant Regulations,* Chapter 2, SCR, June 2019. https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

[106] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

Table 8-4. Rank Remaining NO_X Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies	Potential Control Efficiency (%)
NO_X	SCR SNCR	50-80 (Base Case) 30-50

8.2.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per **Table 8-4**, SCR is the highest ranking potentially feasible control technology for the C2 boiler. EKPC is proposing continued operation of the SCR as it is the highest ranked control option.

8.2.6 Selection of BACT (Step 5)

8.2.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

After the C2 Co-Firing Project, C2 will not be subject to any NSPS or NESHAP standard for NO_X, and thus there is no floor for an allowable NO_X BACT limit. Regarding Title 401 of the Kentucky Administrative Rules, the co-fired C2 boiler is subject to 401 KAR 61:015; however, it does not include a NO_X emissions limit.

Additionally, paragraph 53 of the September 24, 2007 Consent Decree restricts NO_X emissions from the existing coal-fired C2 boiler system to 0.080 lb/MMBtu. EKPC demonstrates compliance with this emission limit using a NO_X CEMS.

8.2.6.2 Summary of RBLC Review

Table D-2.1 of **Appendix D** for coal- and multifuel-fired EGU utility and large industrial boilers. From this full RBLC export, **Table 8-5** captures the RBLC entries that have a NO_X emission limit for coal-fired utility boiler lower than the proposed emission limit of 0.08 lb/MMBtu.

Table 8-5. RBLC Entries for Coal and Multi-Fuel Units

RBLC ID	Facility	Heat Input Rating		NO_X Limit		Averaging Period
WY-0064	Dry Fork Station	385	MW	0.05	lb/MMBtu	12-Mo Rolling
WY-0063	Wygen 3	1,300	MMBtu/hr	0.05	lb/MMBtu	12-Mo Rolling

The NO_X limit proposed by EKPC is lower than the multifuel units identified in the RBLC search. The Dry Fork (WY-0064) and WYGEN 3 (WY-0063) projects are neither multifuel nor retrofit projects. They involve new pulverized coal boilers with 0.05 lb NO_X/MMBtu emission limits, each on a 12-month rolling average. As previously indicated, the burners in the C2 boiler are being modified such that the burners can switch back and forth between firing either coal or NG. This limits the ability to optimize the burners to minimize thermal NO_X during NG combustion and fuel NO_X during coal combustion. Dry Fork and WYGEN 3 are coal only units and were optimized accordingly and not comparable to the retrofitted C2 boiler.

8.2.6.3 NO_X BACT Selection for Co-Fired C2 Boiler

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, the proposed NO_X BACT for operation of the C2 boiler on coal and/or NG using SCR is 0.080 lb NO_X/MMBtu on a

30-day rolling average, applicable at all times including periods of startup and shutdown. Compliance with this limit will be demonstrated through use of a CEMS installed in compliance with 40 CFR Part 75.

8.3 PM/PM_{10}/$PM_{2.5}$ BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for particulate emissions from the C2 boiler modification project. The complexity of the BACT evaluation for particulate emissions is increased because there are two types of PM: (1) filterable or "front-half" PM, which is what has generally been regulated by the NSPS and NESHAP rules (filterable PM is measured by Method 5 for PM), and (2) condensable or "back-half" PM, which is not regulated by NSPS or NESHAP rules (CPM is a component of total PM_{10} and total $PM_{2.5}$ and is measured by Method 202). Air pollution control strategies differ for filterable PM and CPM, but control options for both PM emissions contributions are considered for the PM BACT analysis.

There are three size ranges of filterable particulate, based on aerodynamic diameter, currently regulated under the PSD program: PM (up to 30 μm), PM_{10} (up to 10 μm), and $PM_{2.5}$ (up to 2.5 μm). Control techniques for filterable PM also reduce filterable PM_{10} and filterable $PM_{2.5}$. Therefore, the PM BACT analyses for filterable PM will also satisfy BACT for the filterable portion of PM_{10} and $PM_{2.5}$.

Filterable and CPM are fundamentally different. While filterable emissions are well understood, condensable emissions are more complex and more difficult to measure accurately. For filterable PM, which is captured by traditional PM control devices (e.g., baghouses, ESPs, and wet scrubbers), all coal-fired boilers are capable of achieving essentially the same emission rate regardless of combustion type or fuel type. Once CPM emissions, which may contain H_2SO_4 and HNO_3, high molecular weight organics (i.e., molecules with 25 or more carbon atoms), and other compounds not well controlled by traditional particulate control devices, are included, the achievable emission rate is more variable.

8.3.1 Background on Pollutant Formation

The composition and emission levels of filterable PM from coal-fired boilers are a complex function of boiler firing configuration, boiler operating parameters, pollution control equipment, and coal properties. Uncontrolled PM emissions include ash from coal combustion as well as unburned carbon resulting from incomplete combustion. Pulverized coal systems such as EKPC's C2 boiler system achieve high combustion efficiencies, such that filterable PM emissions are primarily composed of inorganic ash residues. Intermittent filterable PM emissions from coal-fired boilers also occur during periodic soot blowing operations used to dislodge ash from the boiler and exhaust components.

Due to the low ash and sulfur contents of gaseous fuel, filterable PM emissions from NG combustion in boilers are low relative to other fuels. These emissions are typically associated with larger molecular weight hydrocarbons that are not fully combusted. Maintenance issues and poor air/fuel mixing may increase filterable PM emissions from NG combustion.

In contrast to filterable particulate, CPM is the portion of PM emissions that exhausts from the stack in gaseous form but condenses to form homogenous and/or heterogenous aerosol particulate matter once mixed with the cooler ambient air. CPM results from sulfur in the fuel and the resultant sulfate formation (e.g., H_2SO_4, $(NH_4)_2SO_4$, etc.), NO_X being oxidized to a resultant nitrate (e.g., HNO_3, NH_4NO_3, etc.), and high molecular weight organics although the CPM emitted from coal-fired boilers is primarily inorganic in nature. All CPM is less than 2.5 μm in diameter and is classified as the condensable portion of both PM_{10} and $PM_{2.5}$.

A boiler operating without an SCR will have lower CPM emissions than a similar unit operating with an SCR. The increased CPM emissions result from the formation of ammonium sulfates from unreacted ammonia in the control system. Accordingly, emission estimates for total $PM_{10}/PM_{2.5}$ emissions when utilizing an SCR for NO_X emissions reductions are higher than the total $PM_{10}/PM_{2.5}$ emissions anticipated from boiler systems that do not utilize NO_X controls.

The current C2 boiler system uses a PJFF to control filterable PM emissions from coal combustion.

8.3.2 Identification of Potential Control Technologies (Step 1)

The available control technologies identified for PM, PM_{10}, and $PM_{2.5}$ emissions are listed in the following table.

Table 8-6. Potential PM Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies
Filterable $PM/PM_{10}/PM_{2.5}$	Dry FGD with Baghouse/Fabric Filter ESP/Wet ESP Wet Scrubber Cyclone/Multicyclone Good Combustion Practices

8.3.2.1 Dry FGD with Baghouse/Fabric Filter

Dry FGD is a post-combustion technology involving the reaction of alkaline reagent with acid gases. The most common injection chemicals include sodium bisulfite ($NaHSO_3$), sodium carbonate (Na_2CO_3) or Trona, and hydrated lime ($Ca(OH)_2$). The sorbents or reactants utilize their physical and chemical properties to react with or adsorb condensable PM (e.g., H_2SO_4) and other acid gases to produce a solid byproduct that can be collected in the particulate control system.[107] Dry sorbent injection (DSI) can be employed as a dry FGD, or as a duct sorbent injection with less physical infrastructure (e.g., absorber towers for residence time, etc.) than a full FGD system. The reduced availability of acid gases in the exhaust stream reduces condensable PM formation because the primary inorganic contributor to CPM emissions are acid gases such as SO_2, HCl, and H_2SO_4.

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media. While the fabric itself performs a portion of the filtering, its main role is to be the support media for the filter cake that develops on its surface. The filter cake is responsible for the efficient filtering of fine particulate. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches a target level.[108] Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for filterable PM emissions.[109]

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[107] EPA Memo, *Control of Total PM Emissions*, from Office of Air Quality Planning and Standards U.S. Environmental Protection Agency to EGU NSPS Docket (EPA-HQ-OAR-2011-0044), December, 2011

[108] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[109] Ibid.

8.3.2.2 Dry ESP and Wet ESP

ESPs operate using three fundamental steps: solid particle charging, particle collection, and particle removal. Particle charging is accomplished by ionizing the particles in the flue gas as they pass between electrodes. An ESP then collects the electrically charged particles from the air stream by passing them through a force field that causes them to migrate to large, oppositely charged collector plates. After the particles are collected, the plates are washed or knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP.

A key factor in ESP operation and performance is resistivity. Resistivity is a particle's resistance to electrical conduction. If resistivity is too high, the particle will not carry a charge. If it is too low, the particle will quickly lose its charge and become re-entrained in the gas stream. Temperature, humidity, and particle characteristics all affect resistivity. While ESPs can be designed for large gas volumes (wet or dry) and a wide range of temperatures, they do have disadvantages. Once installed, an ESP is not flexible to changes in operating conditions beyond the original design parameters.[110]

Dry ESP are commonly located either upstream of the air pre-heater (hot-side ESP) or downstream of the air pre-heater (cold-side ESP). In these optimal operating locations, dry ESP operates at a temperature above the dew point of CPM. ESPs are intentionally operated at high temperatures to prevent corrosion problems that can result from condensable acid gases. Therefore, dry ESP would not provide significant CPM emissions removal. In contrast, a wet ESP typically operates in saturated flue gas conditions, where the flue gas is below the dew point of many acid gases and other CPM and, thus, a wet ESP is an available control option for both fine filterable and condensable PM.[111]

The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. An ESP can be designed for either dry or wet applications and can generally achieve approximately 99-99.9% reduction efficiency for filterable PM emissions.

8.3.2.3 Wet Scrubber

Wet scrubbers remove PM by impacting the exhaust gas with the scrubbing solution (usually water). This technology generates wastewater and sludge disposal problems along with substantial energy requirements for pumping water and exhausting the cooled air stream out the stack. The CE offered by wet scrubbing is not as high as the baghouse or ESP. Inlet gas temperatures for wet scrubbers usually range from 4 to 400°C (40 to 750°F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.[112] A wet scrubber can generally achieve approximately 80-99% reduction efficiency for filterable PM emissions. Wet scrubbers operating as FGD designed to control SO_2 emissions are capable of removing acid gases that contribute to inorganic CPM.

8.3.2.4 Cyclone/Multicyclone

Cyclones use inertia to remove particles from an exhaust stream. The cyclone imparts centrifugal force on the exhaust, typically within a conical shaped chamber. A double vortex is created inside the cyclone body, and the incoming gas is forced into a circular motion down the cyclone near the inner surface of the cyclone

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[110] Cooper, C. David and F.C. Alley. *Air Pollution Control: A Design Approach*. 2nd Ed. Waveland Press Inc.: Prospect Heights, IL, 1994.

[111] EPA Memo, *Control of Total PM Emissions*, from Office of Air Quality Planning and Standards U.S. Environmental Protection Agency to EGU NSPS Docket (EPA-HQ-OAR-2011-0044), December, 2011

[112] U.S. EPA, *Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Venturi Scrubbers*, EPA-452/F-03-017.

tube. At the bottom of the cyclone, the gas travels up through the center of the tube and out of the top of the cyclone. Filterable PM is propelled toward the cyclone walls by centrifugal force, but this movement is opposed by the fluid drag force of the gas traveling out of the cyclone. For larger particles, the centrifugal force exceeds the drag force, so the particles are collected. For small particles, the drag force exceeds the centrifugal force and causes the particles to leave the cyclone with the exiting gas.

Multiple cyclones (multicyclones) can be operated in parallel to accommodate higher inlet flowrates when compared to a single cyclone unit. The allowable inlet gas temperature for a cyclone is limited by the type of construction material but can be as high as 540°C (1,000°F).[113] Cyclones are generally used as pre-cleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower CE of smaller particles from a cyclone.[114] The CE range for high efficiency single cyclones is 30-90% for PM_{10} and 20-70% for $PM_{2.5}$. The use of multicyclones leads to greater PM CE than from a single cyclone, resulting in control efficiencies in the range of 80-95% for PM_5.[115] Cyclones can only offer filterable PM emissions removal due to the mechanical nature of the pollutant removal mechanism and no specific design features that would remove precursors to CPM emissions formation.

8.3.2.5 Good Combustion Practices

Operation and maintenance of the boiler system in accordance with good air pollution control practices and with good combustion practices minimizes PM emissions. Maintaining high levels of combustion efficiency in coal-fired boilers inhibits the formation of PM from unburned carbon. Likewise, by maintaining appropriate air/fuel mixing in NG-fired boilers, PM emissions are minimized by ensuring larger molecular weight HC are fully combusted. While the coal-fired boiler system RBLC entries identify various add-on control technologies for PM emissions, control strategies identified by the RBLC search for NG-fired utility boilers (>1,000 MMBtu/hr capacity) are limited to good combustion practices and proper burner design and operations.[116]

8.3.3 Elimination of Technically Infeasible Control Options (Step 2)

Of the PM control technologies listed in the previous section, the ESP is considered technically infeasible. Due to the co-firing strategy for the C2 boiler system, which will involve the simultaneous firing of coal and NG burners in different combinations, the exhaust stream will be variable. An ESP is not flexible to changes in operating conditions beyond the original design parameters. As such, this control technology is not suitable for the C2 boiler modification project.

While several coal-fired boilers are listed in the RBLC as using ESP technology along with wet FGD systems for PM control, these utility boilers do not co-fire NG.[117] Given the inherent variability in the proposed operation of the post-modification C2 boiler system, this control strategy is not considered technically feasible for the C2 boiler project. Moreover, an ESP is no more effective than a baghouse/fabric filter at controlling filterable PM, both are capable of 99 to 99.9% control efficiency.

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[113] Ibid.

[114] Ibid.

[115] U.S. EPA, *Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones*, EPA-452/F-03-005

[116] Given the scope of the co-fire modification project, the use of natural gas only fuel is not considered available for this project.

[117] According to RBLC search results for coal-fired utility boilers with PM BACT limits established in permits issued since 2010, Limestone Electric Generating Station (TX-0700), Jim Bridger Power Plant (WY-0073), and Detroit Edison-Monroe (MI-0399) each operate ESP/WFGD systems to control PM emissions.

8.3.4 Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of CE in **Table 8-7**.

Table 8-7. Rank Remaining PM/PM_{10}/$PM_{2.5}$ Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies	Potential Control Efficiency (%)
PM/PM_{10}/$PM_{2.5}$	Dry FGD with Baghouse/Fabric Filter Wet Scrubber Cyclone/Multicyclone Good Combustion Practices	99.9 (Base Case) 99 95 Reduction Varies

8.3.5 Evaluation of Most Stringent Control Technologies (Step 4)

A dry FGD with baghouse/fabric filter has the highest CE of any of the PM control options listed under Step 3 of this BACT evaluation. The current C2 boiler system uses a CDS (specific type of dry FGD) and PJFF to control filterable and condensable PM emissions from coal combustion. This is consistent with the control strategy identified in the majority of RBLC entries for coal-fired utility boiler PM BACT determinations permitted since 2006.

The remaining add-on PM control devices (i.e., wet scrubber and cyclone) are not considered further since the highest efficiency control device is proposed as BACT. As fabric filters can be paired with good combustion practices, the combination of the CDS/PJFF and good combustion practices represents the most effective control option available for the co-fired boiler system.

The selected BACT strategy does not result in disproportionate environmental impacts relative to other PM control options. A baghouse generates bottom ash that requires disposal. Similarly, the same waste generation activity would also be associated with ESP technology, while scrubber technology would generate a wastewater stream containing this same material.

8.3.6 Selection of BACT (Step 5)

8.3.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The current coal-fired C2 boiler system is subject to a variety of filterable PM limits under Kentucky and federal air quality requirements identified in the current air permit. Specifically, filterable PM emissions are restricted to 0.23 lb/MMBtu under 401 KAR 61:015. Additionally, the Kentucky BART SIP and paragraph 84 of the September 24, 2007 Consent Decree each restrict filterable PM emissions from the existing coal-fired C2 boiler system to 0.030 lb/MMBtu. EKPC demonstrates compliance with these three filterable PM limits via an annual Method 5 performance test with an option to reduce the testing frequency to a biennial schedule based on the results of the test (less than 0.015 lb/MMBtu).

The MATS filterable PM emission limit is 0.010 lb/MMBtu as of July 6, 2027. Following the proposed co-firing modification project, unless the MATS revisions are vacated by the Courts in whole or in part or remanded to EPA for further revisions prior to the issuance of the permit at issue, the MATS standard for filterable PM emissions would apply to the C2 boiler system.

The C2 boiler is not currently subject to any state or federal air regulations imposing emission limits/standards for CPM that could set the floor for the total PM_{10}/$PM_{2.5}$ BACT determination.

8.3.6.2 Summary of RBLC Review

Appendix D presents a summary of RBLC entries for coal- and multifuel-fired EGU utility and large industrial boilers. With respect to total PM/PM_{10}/$PM_{2.5}$ emission limits for coal-fired boilers referenced in Table D-2.5 of **Appendix D**, only the Craig Electric Generating Station Unit 3 coal boiler (RBLC ID CO-0072) total PM and total PM_{10} emission limits (0.022 lb total PM/MMBtu and 0.020 lb total PM_{10}/MMBtu) are associated with an operating coal-fired boiler using similar subcritical, pulverized coal boiler technology and equipped with a similar PM air pollution control system to the C2 boiler. However, this Craig Generating Station Unit 3 boiler uses low-sulfur subbituminous coal and is not equipped with a SCR for NO_X emissions control which would collectively produce a non-representative CPM emissions profile in comparison to the C2 boiler. Use of SCR increases CPM formation from creation of ammonium-based salts, and higher sulfur coal increases CPM formation from higher levels of H_2SO_4 emissions and other sulfate-based inorganic CPM contributors. Based on these source-specific boiler design and operating considerations, EKPC considers the proposed C2 boiler filterable and condensable PM BACT limit to be comparably stringent to the lowest total PM/PM_{10}/$PM_{2.5}$ included in the RBLC for similar sources.

8.3.6.3 PM/PM_{10}/$PM_{2.5}$ BACT Selection for CO-Fired C2 Boiler

In consideration of these findings, EKPC proposes a combined filterable and condensable PM BACT limit of 0.030 lb/MMBtu (3-hour average) during all periods of operation except startup and shutdown when firing NG alone or in combination with coal. Compliance with this total PM BACT limit for the C2 boiler will be demonstrated by conducting initial stack testing using applicable reference methods, and EKPC will use the existing DFGD/PJFF and good combustion practices to ensure compliance with this limit.

8.3.6.4 PM/PM_{10}/$PM_{2.5}$ BACT Selection for Co-Fired C2 Boiler Startup and Shutdown

During periods of startup and shutdown, EKPC proposes to comply with the relevant portions of the work practice standards outlined in 401 KAR 61:015 Section 9.

8.4 H_2SO_4 BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for H_2SO_4 emissions from the co-firing operations proposed for C2. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of NG as a low sulfur fuel with coal to mitigate H_2SO_4 emissions from the C2 boiler.

8.4.1 Background on Pollutant Formation

Similar to the explanation provided in the CCGT H_2SO_4 BACT analysis, H_2SO_4 emissions from the C2 boiler result from the reaction between SO_3 and water. SO_3 is formed from the oxidation of fuel bound sulfur during combustion (where a relatively minimal amount of SO_3 is generated) and on the catalyst in the downstream SCR, with the extent of SO_3 formation dependent upon the sulfur content of the fuel and other chemical parameters within the SCR, air preheater, and within the CDS scrubber for SO_2/H_2SO_4 control.

8.4.2 Identification of Potential Control Technologies (Step 1)

The available control options identified for H_2SO_4 are listed in **Table 8-8**.

Table 8-8. Potential H_2SO_4 Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies
H_2SO_4	Dry FGD with Baghouse/Fabric Filter Wet FGD with Wet ESP Duct Sorbent Injection

See Section 8.3.2 for the descriptions of the function of the BH or wet ESP.

8.4.2.1 FGD Scrubbers

FGD systems remove H_2SO_4 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts.[118] The reaction of SO_3 with the alkaline chemical can be performed using either a wet or dry contact system.

- Wet FGD scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems generate wastewater and wet sludge streams requiring treatment and disposal.
- In dry FGD systems, dry hydrated lime is injected into the flue gas duct and an atomized alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form the reaction of the alkaline slurry with SO_3 are dried by heat contained in the exhaust stream—this evaporates the water from the lime slurry and the remaining salts are subsequently removed by downstream particulate control equipment.

The CDS system at Cooper Station functions similarly to a dry FGD system. The sorbent is in a higher concentration in the slurry compared to a wet FGD and the water is evaporated from the slurry similarly to a dry FGD system. For the purposes of this analysis and comparisons to other sources, the CDS is being considered a dry FGD system. Refer to Section 8.3.2.1. for additional discussion of the CDS as a dry FGD system.

8.4.3 Elimination of Technically Infeasible Control Options (Step 2)

An ESP has been ruled technically infeasible for flexible fuel firing in the PM BACT analysis Section 8.3; therefore, it is not an available option for H_2SO_4 control.

8.4.4 Rank of Remaining Control Technologies (Step 3)

A dry FGD scrubber with a baghouse or fabric filter is widely considered the most effective control technology for H_2SO_4 removal. The existing CDS and PJFF system functions similarly to a dry FGD scrubber with a baghouse. A separate DSI system is redundant to dry FGD (i.e., it creates an alkaline environment for H_2SO_4 neutralization); therefore, adding an additional DSI system would have negligible impact on H_2SO_4 emissions. Thus, a dry FGD scrubber with a baghouse or fabric filter is the highest-ranking option. A CDS and PJFF are already in operation to control emissions from the C2 boiler.

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118 U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Flue Gas Desulfurization – Wet, Spray Dry, and Dry Scrubbers*, EPA-452/F-03-034.

8.4.5 Evaluation of Most Stringent Control Technologies (Step 4)

A dry FGD scrubber with a baghouse or fabric filter is widely considered as the most effective control technology for H_2SO_4 removal. This H_2SO_4 control device system (i.e., CDS and PJFF) will continue to be employed by EKPC on the C2 boiler.

8.4.6 Selection of BACT (Step 5)

8.4.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

After the C2 Co-Firing Project, C2 still will not be subject to any NSPS or NESHAP standard for H_2SO_4, and thus there is no BACT floor. The co-fired C2 boiler will also not be subject to any emission limit under Title 401 of the Kentucky Administrative Rules.

8.4.6.2 Summary of RBLC Review

EKPC has included a summary of RBLC entries in Table D-2.6 of **Appendix D** for coal- and multifuel-fired EGU utility and large industrial boilers. After applying the RBLC screening criteria noted in the introduction to this C2 BACT analysis and specifically excluding coal-fired EGU boilers using sub-bituminous coal, EKPC's proposed H_2SO_4 BACT limit for the C2 boiler is lower than or equal to all other RBLC entries.

8.4.6.3 H_2SO_4 BACT Selection for Co-Fired C2 Boiler

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, EKPC has determined that H_2SO_4 BACT for operation of the C2 boiler when co-firing coal and NG is achieved using the CDS and PJFF. The proposed limit is 0.005 lb/MMBtu (3-hr average) and applies at all times except during periods of startup and shutdown. Compliance with this limit will be demonstrated by an initial performance test (EPA Method 8 or approved alternative).

8.4.6.4 H_2SO_4 BACT Selection for Co-Fired C2 Boiler Startup and Shutdown

During periods of startup and shutdown, EKPC proposes to comply with the relevant portions of the work practice standards outlined in 401 KAR 61:015 Section 9.

8.5 GHG BACT Evaluation

This section contains a high-level review of GHG pollutant formation and possible control technologies for the C2 Co-Fire Project. The vast majority of GHG emissions, on a CO_2e basis, from fossil-fuel boiler are in the form of CO_2 with applicable emission factors of 205.6 lb/MMBtu from coal and 116.98 lb/MMBtu from NG combustion. Emission rates of CH_4 and N_2O from these EGU boilers are extremely low in the magnitude of 0.0243 and 0.0022 lb/MMBtu from coal and 0.0035 and 0.0002 lb/MMBtu from NG combustion, respectively. Considering the new GWP of 28 for CH_4 and 265 for N_2O, even on a CO_2e basis, the emission rates of CH_4 and N_2O from these EGU boilers are extremely low in the magnitude of 0.68 and 0.94 lb/MMBtu from coal and 0.06 and 0.06 lb/MMBtu from NG combustion, respectively. Therefore, given that CO_2e emissions from the C2 boiler are made up of almost entirely CO_2, EKPC is presenting a GHG BACT analysis for CO_2 and all conclusions are representative for all GHG pollutants unless otherwise noted.

8.5.1 Background on Pollutant Formation

See Section 7.6.1.

8.5.2 Identification of Potential Control Technologies (Step 1)

EKPC identified potentially applicable emission control technologies for CO_2 from EGU boilers by researching the EPA control technology database, guidance from EPA, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. EKPC also relied on the large body of information compiled by EPA from various rulemakings that were considered, such as the NSPS Subparts UUUUa and UUUUb preambles. An RBLC search was also conducted to identify technologies and corresponding GHG emission limits that have been approved by regulatory agencies in permit actions. The RBLC search is summarized below and indicates no add-on controls for GHG were required for any of the facilities. The RBLC entries list a variant of good combustion practices, efficient operation, state-of-the-art technology, or low emitting fuels (e.g., pipeline-quality NG and ULSFO).

The project is defined as a modification to C2 to allow up to 100% NG firing, or co-firing coal and NG at various levels. Although the proposed introduction of NG co-firing for the C2 boiler does introduce a lower carbon fuel that offers reduced CO_2 emissions when firing NG as compared to firing coal, EKPC needs to retain the flexibility to use coal in the C2 boiler on both a short-term and long-term basis to continue meeting the energy and capacity needs of its 16 rural owner- member cooperatives and to support the projected increased winter grid demands. Therefore, low carbon fuels are considered to be an available GHG control option, but only to the extent that use of such fuels does not adversely impact the key fuel flexibility and grid reliability objectives of the proposed C2 co-firing project.

The control technologies listed in **Table 8-9** were identified as candidates for controlling GHG emissions from the generating units.

Table 8-9. Potential GHG Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies
GHG	CCS Low Carbon Fuels Efficient Boiler Operation and Good Combustion Practices

8.5.2.1 CCS

The same analysis in Section 7.6.2.1 applies to the C2 Co-Firing Project.

8.5.2.2 Lower Carbon Fuels

CO_2 is produced as a combustion product of any carbon containing fuel. The carbon content of the fuel, relative to its Btu value, can have significant impact on the overall GHG emissions. Gaseous fuels such as NG have less GHG emissions per Btu than liquid or solid fuels. The use of lower carbon content gaseous fuels such as NG compared to the use of higher carbon-containing fuels such as coal, pet-coke or residual FOs, can reduce CO_2 emissions from combustion. The use of lower carbon containing fuels in coal-fired boilers is an effective means to reduce the generation of CO_2 during the combustion process.

8.5.2.3 Efficient Boiler Operation and Good Combustion, Operating, and Maintenance Practices

CO_2 emissions are directly related to the quantity of fuel burned; therefore, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. The only useful means to reduce CO_2 from a fossil fuel combustion process is to minimize the amount of fuel used, which is achieved by establishing a more thermally efficient process, or by substitution of a lower GHG emitting fuel. The largest efficiency losses for an existing large coal-fired boiler are inherent in the boiler design, heat transfer, steam quality/stability, combustion air, and heat recovery.

Heat rate for a coal-fired EGU is generally defined as the total fuel heat input (Btu) required per unit of power generation (kWh) and is commonly expressed in units of Btu/kWh or MMBtu/MWh. Heat rate is the most direct indicator of EGU efficiency making it a useful tool for GHG emissions reductions strategies. However, heat rate can be calculated and reflected in two different ways: gross heat rate and net heat rate. Gross heat rate is the total fuel heat input to the boiler divided by the gross power generation of the unit's ST generator. Gross heat rate is an indicator of the efficiency of the unit's ST and boiler but does not reflect the efficiency of any auxiliary power users within the overall EGU. Gross heat rate is easier to calculate for a station given that auxiliary power is not always monitored and can be unequally distributed within a power plant amongst its EGUs.[119] GHG emissions standards are expressed on a mass of CO_2 emitted per unit of energy production basis on a gross basis, evaluating boiler efficiency on a gross heat rate basis offers a more direct measure of the boiler's GHG emissions profile and associated opportunities to consume less fuel per unit of energy production. Auxiliary power consumption which influences the net power output, can vary significantly from station-to-station based on a wide range of EGU design and operating variables which are difficult to compile, analyze, and compare for the purposes of GHG emission limit setting. Therefore, only those boiler efficiency measures with the potential to directly influence the gross heat rate are carried in this GHG BACT analysis for the C2 co-firing modification.

Below is a sample list of routine activities completed by plant personnel to maintain gross heat rate efficiency of C2.

- Pulverizer grinding zone overhauls
- Pulverizer performance tuning, i.e., coal fineness test, combustion tuning, loss on ignition (LOI) test
- ABB Boiler tuning annually
- Periodic performance tune-ups of C2, as specified in 40 CFR 63.10021(e)(1) through (9), which includes burner inspections at least once every 36 calendar months
- Air flow calibrations performed on FD, ID, and PA fans
- Air heater leakage tests
- Full Boiler Assessment at 5-year intervals

Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation, and thus are relevant from a GHG emissions minimization/mitigation perspective.

8.5.3 Elimination of Technically Infeasible Control Options (Step 2)

A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits.

8.5.3.1 CCS

CCS involves (1) "capturing" and separating the CO_2 from the exhaust of the emission source; (2) transporting the CO_2 to an appropriate injection site; and (3) sequestering the CO_2 at a suitable site. For

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[119] Sargent & Lundy, Heat Rate Improvements Method Costs and Limitations Memo, March 2023, NSPS UUUUb Docket ID EPA-HQ-OAR-2023-0072-0018, available at https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0018

CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

See Section 7.6.3.1 for a complete description of technical infeasibility for the CTs, which are relevant to the C2 Co-Firing Project. Key differences are as follows:

- The technology needed to compress CO_2 to supercritical conditions is available; however, specialized technologies require high operating energy requirements. It is important to understand that there are technical challenges with compressing the expected volume of CO_2 generated from both CTs (or both CTs **and** the C2 co-firing operation). To complete this component of the CCS, EKPC would be required to co-locate a new chemical manufacturing facility at Cooper Station.
- Based on available data, CO_2 capture using solvents, solid sorbents or membranes has only been used on a full-scale basis at a 115 MW coal-fired power plant called the SaskPower's Boundary Dam 3 Carbon Capture Facility near Estevan, Saskatchewan, Canada (non-PSD). [120,121,122]
- A review of DOE NETL research and development awards related to post-combustion capture of CO_2 indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus; however, the existence of several FEED studies indicates that commercial implementation is beginning to move forward.[123] For example, a FEED study is underway for a commercial-scale carbon capture facility retrofitted at the Delta Energy Center in Pittsburg, CA, capable of capturing 2.4 MM tons of CO_2 per year.[124] Another pilot-scale FEED study is underway for a 1.7 MM ton/yr CO_2 capture project at Louisville Gas & Electric's Cane Run Station Unit #7; however, they have not demonstrated viability on a commercial scale.[125]
- Although FEED studies indicate heightened interest in exploring potential implementation opportunities for CCS, EKPC is unaware of a single successful CCS deployment for an existing or new large coal-fired or coal/NG co-fired boiler in the US.
- Since there are no existing CO_2 pipelines in Kentucky or in adjacent states (see Figure 7-1), EKPC would need to construct a CO_2 pipeline to a storage location if it were to pursue carbon sequestration as a CO_2 control option.[126] While it may be technically feasible to construct a CO_2 pipeline, considerations regarding land use and availability need to be made, as well as the distance to the nearest Class VI well.

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[120] NETL CCS Database available at: https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[121] Global Carbon Capture and Storage Institute, Facilities Database available at: https://co2re.co/FacilityData

[122] Boundary Dam Carbon Capture Project

[123] Website reviewed June 2024: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[124] *Front-End Engineering Design for a CO_2 Capture System at Calpine's Delta Energy Center,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032149, start date February 1, 2022.

[125] *CO_2 Capture at Louisville Gas & Electric Cane Run Natural Gas Combined Cycle Power Plant,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032223, start date December 22, 2022. https://netl.doe.gov/sites/default/files/netl-file/24CM/24CM_PSCC_5_Berger.pdf

[126] *Active CO_2 Pipelines in the NPMS,* U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration National Pipeline Mapping System, March 11, 2024. https://www.npms.phmsa.dot.gov/Documents/NPMS_CO2_Pipelines_Map.pdf

- While capture-only technologies may be technologically available at a small-scale, and besides the lack of CO_2 pipelines anywhere in Kentucky, another limiting factor is the availability of a mechanism for EKPC to permanently store the captured CO_2.
- NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[127] According to the database, there are no potential sequestration sites in the vicinity of the proposed Cooper Project. All other potential sites are located further away, whereas in Kentucky and Virginia there are pilot-scale tests or unbuilt facilities still in development.
- Kentucky has a Class II well program that covers the underground injection of CO_2 for purposes other than permanent storage. However, the Class VI injection well permitting requirements for a commercial-scale CCS operation would reside with EPA as Kentucky has not been granted primacy for Class VI injection well permit issuance.[128] No EPA-issued Class VI injection well permits have been issued for a Kentucky underground injection site.[129]

CCS storage may be an available option in those regions of the country that have access to a Class VI well. As stated above, the Commonwealth does not have a CO_2 pipeline, nor does Kentucky have a Class VI well that allows for permanent storage of CO_2.

CCS technology, specifically post-combustion CO_2 capture technology, is not commercially available as it has not yet been successfully implemented on a large-scale basis such as a 2,000+ MMBtu/hr coal or coal/NG co-fired boiler. Moreover, the energy costs are prohibitive, and while more efficient approaches are being investigated, none have currently been developed past the pilot-stage.

Review of the application submitted for the RBLC IA-0101 Ottumwa Generating Station (as the only utility-scale boiler to list a GHG BACT limit in the RBLC), also confirmed that CCS was identified as technically infeasible. EKPC has concluded that CCS technology is not technically feasible at this time for the C2 Co-Firing Project.

8.5.3.2 Low Carbon Fuels

An option to use a higher-ranked coal than bituminous coals would not result in a lower CO_2e than the project's use of NG, so it is not considered a control option. Moreover, C2 was previously permitted to fire a wood waste blend with coal, but it was canceled for operational concerns; therefore, bio-fuels is not considered a viable control option at the Cooper Station. Co-firing coal with NG is a viable control option under the low carbon fuels category of GHG emissions reduction techniques.

8.5.3.3 Efficient Boiler Operations and Good Combustion, Operating, and Maintenance Practices

The C2 Co-Firing Project is designed around introducing NG co-firing without affecting the reliability and availability afforded by the existing coal-firing within this area of Kentucky. Therefore, there is neither an opportunity to completely change out all coal-fired burners with advanced NG-fired burners, or an opportunity to redesign heat generation and electrical output system associated with C2.

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[127] Carbon Capture and Storage Database maintained by the NETL, accessed July 2021 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[128] https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0

[129] https://udr.epa.gov/ords/uicdr/r/uicdr_ext/uicdr-pub/map

The Efficient Boiler Operations and Good Combustion, Operating, and Maintenance Practices currently performed by EKPC are technically feasible work practice standards for the C2 Boiler.

8.5.4 Rank of Remaining Control Technologies (Step 3)

Addition of low carbon fuels, efficient boiler operation and good combustion, operating, and maintenance practices are the only remaining control method. Specific GHG emissions reduction efficiencies for boiler efficiency improvements are not applicable for this control method.

The remaining control technologies are ranked in order of CE below in **Table 8-10**.

Table 8-10. Rank Remaining GHG Control Technologies – Co-Fired C2 Boiler

Pollutant	Control Technologies	Potential Control Efficiency (%)
GHG	Low Carbon Fuels Efficient Boiler Operations	7 to 41% Reduction Varies

8.5.5 Evaluation of Most Stringent Control Technologies (Step 4)

The C2 Co-Firing Project is designed to have an option for co-firing coal with NG or to fire 100% NG, while maintaining the original ability to fire 100% pulverized coal.

Per **Table 8-10**, use of NG, by itself or co-fired with coal, as a lower carbon fuel is the highest ranking potentially feasible control technology for the C2 Boiler. EKPC is proposing to use the co-firing option as it is the highest ranked control option, while maintaining the ability to fire 100% pulverized coal for reliability purposes.

From among the available boiler efficiency improvement measures, the project is proceeding with combustion control optimization. For example, the project includes an upgraded burner management system and combustion control system paradigm to navigate the co-firing system. New fuel gas conditioning (FGC) equipment will be provided to clean, dry and reduce pressure of the gas being delivered to the low-pressure regulating skid within C2. The FGC equipment will consist of a knock-out drum, filter separator, drains tank, NG heater, and high-pressure regulating skid. The NG heater is incorporated to dry the NG and hold it above dew point after pressure regulation at the HP Skid.

8.5.6 Selection of BACT (Step 5)

8.5.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

EKPC understands that a BACT limit must be at least as stringent as the most stringent applicable federal or state regulation. As discussed infra, Unit 2 is not subject to Subpart UUUUb. In any case, multiple petitioners are challenging the legality of Subpart UUUUb, in a lawsuit which is pending at the time of submittal of this application. EKPC acknowledges the potential that Subpart UUUUb could be vacated by the Courts in whole or in part or remanded to EPA for revisions prior to the issuance of the permit at issue. EKPC proposes BACT as discussed below.

8.5.6.2 Summary of RBLC Review

As shown in **Appendix D**, EKPC queried the RBLC database to identify GHG BACT limits for similar coal boilers to the modified C2 unit. **Table 8-11** summarizes the CO_2 and CO_2e RBLC entries for utility and large industrial boilers/furnaces combusting coal.

Table 8-11. GHG RBLC Entries for Coal-Fired Utility/Large Boilers

<table>
<tr><th>RBLC ID</th><th>Facility</th><th>Permitted GHG Limit</th><th>Units</th><th>Averaging Period</th></tr>
<tr><td rowspan="3">IA-0101</td><td rowspan="3">Ottumwa Generating Station
Boiler #1, Boiler, Dry Bottom
Tangentially Fired, Coal Fired
8,669 MMBtu/hr (726 MW)
PSD-BACT</td><td>8,000,325 (CO_2e)</td><td>tpy ea.</td><td>Annual[a]</td></tr>
<tr><td colspan="3">Good combustion controls/practices</td></tr>
<tr><td>2,927.1 (CO_2)</td><td>lb/MWh(net)</td><td>30-Days[b]</td></tr>
</table>

a. Compliance shall be determined by multiplying the mass of each GHG as defined in 40 CFR §98.6 by its respective GWP as defined in 40 CFR Part 98, Table A-1 and summing the results. The version of Table A-1 used shall be the version promulgated as of the date of the issuance of permit 78-A-019-P10, which listed the following GWPs: CO_2 = 1, CH_4 = 21, & N_2O = 310
The CO_2 mass emissions shall be obtained from the required CMS and the mass emissions for CH_4 and N_2O shall be determined based on the most recent stack test results approved by the Department.

b. Standard is a thirty (30) day rolling average not including periods of SSM. MWh = megawatt-hour. MWh (net) shall be determined by subtracting the metered megawatt-hour value for station service from the metered megawatt-hour value for gross generation. Alternatively, net generation may be obtained directly from a power metering device for net generation, if the metering instrument is electrically equivalent to gross generation minus station service.

EKPC then queried the RBLC database to identify utility and large industrial NG-fire boilers with GHG BACT limits. **Table 8-12** summarizes the CO_2 and CO_2e RBLC entries for large boilers combusting NG.

Table 8-12. GHG RBLC Entries for NG-Fired Utility/Large Boilers

<table>
<tr><th>RBLC ID</th><th>Facility</th><th>Permitted GHG Limit</th><th>Units</th><th>Averaging Period</th></tr>
<tr><td rowspan="2">LA-0364</td><td rowspan="2">FG LA Complex ST. James
NG-Fired Utility Boilers 1 & 2
1,200 MMBtu/hr ea.
PSD BACT</td><td>615,294 (CO_2e) ea.</td><td>tpy ea.</td><td>Annual</td></tr>
<tr><td colspan="3">Use of NG or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices</td></tr>
</table>

BACT determinations for related units denote use of NG, energy efficient design options, good combustion controls/practices, and operational/maintenance practices as the methods used to support the BACT emission limitations. Post-combustion capture and sequestration of CO_2 is not required. BACT limits for related utility and large industrial boilers can be found expressed in terms of lb CO_2/MWh-gross, lb CO_2/MWh-net, or tons, typically with a 12-month rolling averaging period.

8.5.6.3 CO_2 BACT Limit Selection for Co-Fired C2 Boiler

EKPC's focus on the future is to achieve a reduction of CO_2 by co-firing coal with NG from C2's existing emission rate when firing solely pulverized coal. With this C2 Co-Firing Project, EKPC goals are to reduce

GHG and protect its most dependable electric-generating resources. The co-firing project will protect nearly half of EKPC's existing generating capacity while reducing CO_2 emissions.[130]

EKPC is proposing BACT for CO_2 for the C2 Co-Firing Project as 2,074 lb CO_2/MWh-g for combustion of coal with NG demonstrated on a 12-month rolling basis. Compliance with the proposed C2 CO_2 BACT limit will be demonstrated in accordance with 40 CFR Part 75 procedures. This proposed C2 CO_2 BACT limit is expected to achieve a 7% reduction in the CO_2 emission rate (lb CO_2/MWh-g) under a co-firing fuel mix of approximately 83% coal and 17% NG as compared to the current operations with 100% coal.

[130] https://www.ekpc.coop/sites/default/files/PDFs/2024/2024-11-14__EKPC_announces_power_plant_projects.pdf

9. BACT ANALYSIS FOR ANCILLARY EQUIPMENT

9.1 Auxiliary Boiler

The proposed 78.32 MMBtu/hr Auxiliary Boiler will be fired with NG. The control technologies listed in the following subsections were obtained from the RBLC database for gas-fired boilers in the size range of the Auxiliary Boiler at Cooper Station and from research of emerging technologies. The RBLC search conducted for this analysis was based on RBLC Process Code 12.310 – Industrial Size Boilers/Furnaces>100 MMBtu/hr and 13.310 – Commercial/Institutional Size Boilers/Furnaces <100 MMBtu/hr over a ten-year period. For the purpose of this analysis, only the entries for boilers firing NG were reviewed.

9.1.1 CO and VOC BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for CO and VOC emissions from the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of oxidation catalysts and good combustion and operating practices to mitigate CO and VOC emissions from the Auxiliary Boiler while firing NG.

9.1.1.1 Background on Pollutant Formation

See Section 8.1.1 for a description on pollutant formation.

9.1.1.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable CO and VOC control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- Oxidation Catalyst
- Good Combustion Controls

Oxidation catalyst and good combustion controls were discussed in detail in Section 7.1 of this application.

9.1.1.3 Elimination of Technically Infeasible Control Options (Step 2)

All options identified in Step 1 are technically feasible.

9.1.1.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are presented in **Table 9-1** in order of control effectiveness.

Table 9-1. Remaining CO and VOC Control Technologies – Auxiliary Boiler

Rank	Control Technology	Potential Control Efficiency (%)
1	Oxidation Catalyst	50-90 for CO, 50-60 for VOC
2	Good Combustion Controls	Reduction Varies

9.1.1.5 Evaluation of Most Stringent Controls (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for the Auxiliary Boiler. EKPC is proposing installation of this option, alongside good combustion and operating practices, as the most effective means for reducing emissions of CO and VOC from the Auxiliary Boiler.

9.1.1.6 Selection of BACT (Step 5)

9.1.1.6.1 Selection of CO BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for CO. As such, there is no floor for an allowable CO BACT limit.

RBLC Review. Except for one RBLC entry, all similar sized NG-fired industrial boilers list good combustion practices as the control method. The Nemadji Trail Energy Center (WI-0300) specifies the use of oxidation catalysts is necessary to achieve a BACT emission limit of 0.0037 lb/MMBtu for CO.

Selection of BACT. Based on good design and operation and use of oxidation catalyst to achieve minimum emissions of CO is determined as the BACT for the Auxiliary Boiler. EKPC proposes a CO BACT emission limit of 0.003 lb/MMBtu on a 3-hour average basis. Compliance with the Auxiliary Boiler CO BACT limit will be based on an initial performance test conducted in accordance with U.S. EPA Method 10, while operating at steady-state conditions.

9.1.1.6.2 Selection of VOC BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. As detailed in Section 5 of this application, the Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for VOC. As such, there is no floor for an allowable VOC BACT limit.

RBLC Review. RBLC database entries for VOC emissions from boilers range from 0.0015 lb/MMBtu to 0.008 lb/MMBtu, with 0.0054 lb/MMBtu being the most prevalent. The two most recent RBLC database entries included in **Appendix D** for the 2023 calendar year were approved at an emission rate of 0.0054 lb VOC/MMBtu.

The Nemadji Trail Energy Center (WI-0300) specifies the use of oxidation catalysts is necessary to achieve a BACT emission limit of 0.0027 lb/MMBtu for VOC. This facility has not commenced construction or demonstrated compliance with the 0.0027 lb VOC/MMBtu emission limit. EKPC is not confident that an emissions limit of 0.0027 lb VOC/MMBtu is achievable in practice for an intermittent use boiler.

Selection of BACT. Based on the control technology evaluation, oxidation catalyst and good design and operating practices to achieve minimum emissions of VOC is determined as the BACT for the Auxiliary Boiler. EKPC proposes a VOC BACT emission limit of 0.0054 lb/MMBtu on a 3-hour average basis. Compliance with the Auxiliary Boiler VOC BACT limit will be based on exclusive use of pipeline quality NG as a clean burning fuel.

9.1.2 NO_X BACT Evaluation

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of ultra LNBs and good combustion and operating practices to mitigate NO_X emissions from the Auxiliary Boiler while firing NG.

9.1.2.1 Background on Pollutant Formation

The three predominant forms of NO_X formation within an industrial boiler are thermal NO_X, prompt NO_X, and fuel NO_X, which are discussed in Section 7.3.1.

9.1.2.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable NO_X control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- $EM_X/SCONO_X$
- SCR
- SNCR
- Ultra Low-NO_X Burners
- Good Combustion Practices

$EM_X/SCONO_X$, SCR and SNCR were discussed in detail in Section 7.3. Ultra LNBs are designed to control fuel and air mixing in order to create larger and more branched flames. This lowers the flame temperature and results in a reduction in thermal NO_X formation. The improved flame structure also reduces the amount of oxygen available in the flame, improving burner efficiency. The low-NO_X levels are achieved by introducing fuel primarily to the pre-mix zones and reducing the amount of fuel being combusted from the pilot nozzle.

9.1.2.3 Elimination of Technically Infeasible Control Options (Step 2)

EM_X technology has not been demonstrated on NG-fired boilers and is determined to be technically infeasible.

All other options identified in Step 1 are technically feasible.

9.1.2.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are presented in **Table 9-2** in order of control effectiveness.

Table 9-2. Rank Remaining NO_X Control Technologies – Auxiliary Boiler

Rank	Control Technology	Potential Control Efficiency (%)[131]
1	SCR	50-90
2	Ultra LNB	~70 (base case)
3	SNCR	40-60
4	Good Combustion Practices	Reduction Varies

[131] The control efficiencies identified in the table for SCR and SNCR represent typical control efficiency ranges for these control technologies and were used for ranking purposes only. The control efficiency for the ultra LNB was calculated based on the vendor guarantee of 9 ppmvd at 3% O_2 compared against an uncontrolled small boiler from AP-42, Table 1.4-1. The percent reductions from SCR and SNCR are general ranges expected from utility boilers which have higher inlet NO_X emissions.

9.1.2.5 Evaluation of Most Stringent Controls (Step 4)

9.1.2.5.1 SCR

EKPC evaluated the environmental, energy, and economic impacts of using SCR. No significant environmental impacts are expected from the operation of SCR. Energy impacts include the consumption of electricity to operate the system. Economic impacts for the installation of SCR are significant. The proposed boiler with normal LNBs has a baseline emission rate of 30 ppmvd at 3 percent O_2. At the proposed capacity utilization and assuming that an SCR is capable of achieving 90 percent control for this installation, this equates to 11 tons of NO_X removed with the control device.

EKPC prepared a cost estimate using the U.S. EPA's Air Pollution Control Cost Estimation Spreadsheet for SCR (June 2019), which is based on Chapter 2 – Selective Catalytic Reduction Cost Manual that was last updated in June 2019.[132] Standard factors were used for a NG-fired boiler using the design specifications of the proposed Auxiliary Boiler. As shown in the complete cost analysis is provided in **Appendix E**, the estimated annualized total annual cost for an SCR would be $302,651 in 2024 dollars. Based on a cost analysis using these values, the cost of purchasing, installing, and operating SCR is approximately $27,230 per ton controlled. This add-on control option would result in adverse economic impacts when compared to the underlying base case, which includes ultra LNBs as part of the design.

Moreover, with the exception of one RBLC entry, which was to control five (5) 46.7 MMBtu/hr waste heat boilers with a total heat input of 233.5 MMBtu/hr, no NG-fired boilers listed in the RBLC with a heat input capacity less than 100 MMBtu/hr have installed SCR. Therefore, based on the environmental, energy, and economic analysis and a review of similar boilers in the RBLC database, SCR is not selected as BACT for control of NO_X emissions from the Auxiliary Boiler.

9.1.2.5.2 Ultra Low-NO_X Burners

Ultra LNBs is the second highest ranking potentially feasible control technology for the Auxiliary Boiler. The proposed Auxiliary Boiler is designed with ultra LNBs capable of achieving 9 ppmvd at 3 percent O_2. Compared with standard LNBs, the base case will achieve a control efficiency of approximately 70 percent. At the proposed capacity utilization and vendor guarantee, this equates to 9 tons of NO_X removed with the control technology. Based on the insignificant environmental and energy impact associated with this technology and the feasibility from an economic standpoint, EKPC is proposing installation of this option, alongside good combustion and operating practices, as the most effective means for reducing emissions of NO_X from the Auxiliary Boiler.

9.1.2.5.3 SNCR

EKPC evaluated the environmental, energy, and economic impacts of using SNCR. No significant environmental impacts are expected from the operation of SNCR. Energy impacts are attributed to only the electricity usage associated with operation of the SNCR itself, which are lower than that of SCR. Similar to SCR, economic impacts for the installation of SNCR are significant. At the proposed capacity utilization and assuming that an SNCR is capable of achieving 60 percent control for this installation, this equates to approximately 7.5 tons of NO_X removed with the control device.

EKPC prepared a cost estimate using the U.S. EPA's Air Pollution Control Cost Estimation Spreadsheet for SCR (June 2019), which is based on Chapter 1 – Selective Noncatalytic Reduction Cost Manual that was last

[132] https://www.epa.gov/sites/default/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm

updated in April 2019.[133] Standard factors were used for a NG-fired boiler using the design specifications of the proposed Auxiliary Boiler. As shown in the complete cost analysis is provided in **Appendix E**, the estimated annualized total annual cost for an SNCR would be $114,134 in 2024 dollars. Based on a cost analysis using these values, the cost of purchasing, installing, and operating SNCR is approximately $15,230 per ton controlled. This add-on control option would result in adverse economic impacts when compared to the underlying base case, which includes ultra LNBs as part of the design.

EKPC has determined that SNCR is not BACT based on the environmental, energy, and economic analysis. This determination is consistent with the RBLC database, as no facilities in the database have installed SNCR for control of NO_X emissions from an NG-fired boiler less than 100 MMBtu/hr.

9.1.2.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. As detailed in Section 5 of this application, the Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for NO_X for NG-fired boilers. As such, there is no floor for an allowable NO_X BACT limit.

RBLC Review. Emission limits in the RBLC database range from 0.006 lb/MMBtu to 0.1 lb/MMBtu, with several recent BACT determinations approved at values of 0.011 lb NO_X/MMBtu and greater, including several units with similar heat input capacity at 0.035 to 0.04 lb/MMBtu in 2022 and 2023. The proposed emission limit is consistent with the emission limits provided in the RBLC database.

The Nutrien US LLC's Kenai Nitrogen Operations Facility (AK-0083) specifies the use of SCR is necessary to achieve a BACT emission limit of 7 ppmvd NO_X at 15 percent O_2. This facility has not commenced construction or demonstrated compliance with their emission limit and EKPC determined SCR to not be cost effective.

Selection of BACT. Based on the control technology evaluation, ultra LNBs with good design and operating practices to achieve minimum emissions of NO_X is determined as the BACT for the Auxiliary Boiler. EKPC proposes a NO_X BACT emission limit of 0.011 lb/MMBtu on a 3-hour average basis. Compliance with the Auxiliary Boiler NO_X BACT limit will be based on an initial performance test conducted in accordance with 40 CFR 60, Appendix A, Method 7.

9.1.3 PM/PM_{10}/$PM_{2.5}$ BACT

The following sections present a review of pollutant formation and possible control technologies for particulate emissions from the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach.

9.1.3.1 Background on Pollutant Formation

See Section 8.3.1 for pollutant formation.

9.1.3.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, potentially applicable PM/PM_{10}/$PM_{2.5}$ control technologies for a NG-fired boiler were identified. The available control options are combustion design controls and use of low sulfur fuel to mitigation CPM formation.

[133] https://www.epa.gov/sites/default/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm

9.1.3.3 Elimination of Technically Infeasible Control Options (Step 2)

All options identified in Step 1 are technically feasible.

9.1.3.4 Rank of Remaining Control Technologies (Step 3)

Implementing combustion design controls and use of low sulfur fuel provides the most effective means for reducing emissions of $PM/PM_{10}/PM_{2.5}$ from the Auxiliary Boiler.

9.1.3.5 Evaluation of Most Stringent Controls (Step 4)

The top and only available and technically feasible PM control options will be applied to achieve compliance with the proposed BACT limit.

9.1.3.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. As detailed in Section 5 of this application, the Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015. While NSPS Subpart Dc does not have a PM emission limit for NG-fired boilers, 401 KAR 59:015 lists a PM emission limit of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)], and as such, the state rule sets the BACT floor.

RBLC Review. Emission limits in the RBLC database range from 0.0007 lb/MMBtu to 0.01 lb/MMBtu, with several recent BACT determinations approved at values of 0.0035 lb/MMBtu and greater, including several units with similar heat input capacity at 0.0075 to 0.008 lb/MMBtu in 2022 and 2023. Based on review of the RBLC database, EKPC believes that the proposed PM, PM_{10}, and $PM_{2.5}$ BACT limit is consistent with established limits for comparable boilers.

Selection of BACT. EKPC proposes good combustion practices and combustion of pipeline-quality NG as BACT for PM. Compliance with the Auxiliary Boiler PM BACT determination will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline-quality NG.

9.1.4 H_2SO_4 BACT

The following sections present a review of pollutant formation and possible control technologies for H_2SO_4 emissions from the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of low sulfur fuels to mitigate H_2SO_4 emissions from the Auxiliary Boiler.

9.1.4.1 Background on Pollutant Formation

See Section 3.1.1.1.1 for an explanation on pollutant formation.

9.1.4.2 Identification of Potential Control Techniques (Step 1)

Emissions of H_2SO_4 depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

- FGD System;
- DSI; and
- Fuel Specification.

Neither FGD systems nor dry sorbent injection systems are listed in the RBLC as BACT for the control of H_2SO_4 emissions for auxiliary boilers. These technologies have not been applied to NG auxiliary boilers due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction. As such, the use of FGD systems and dry sorbent injection systems are not discussed further.

9.1.4.3 Elimination of Technically Infeasible Control Options (Step 2)

Combusting only clean NG, which has an inherently low sulfur content, has a very low potential for generating H_2SO_4 emissions. Fuel specifications are included in RBLC for the control of H_2SO_4 emissions from auxiliary boilers.

Based on the information reviewed for this BACT determination, EKPC has determined that the use of fuel specifications is a technically feasible option for the Auxiliary Boiler at this source.

9.1.4.4 Rank of Remaining Control Technologies (Step 3)

The only remaining control measure identified for control of H_2SO_4 resulting from the operation of the Auxiliary Boiler is fuel specifications.

9.1.4.5 Evaluation of Most Stringent Controls (Step 4)

The top and only available and technically feasible H_2SO_4 control option will be applied to achieve compliance with the proposed BACT limit.

9.1.4.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. There are no applicable NSPS, NESHAP, or State rules to set the BACT floor for H_2SO_4 emissions from an auxiliary boiler.

RBLC Review. Similarly sized NG-fired industrial boilers list combustion of clean/low-sulfur fuels as the control method.

Selection of BACT. EKPC proposes combustion of pipeline-quality NG as BACT for H_2SO_4. Compliance with the Auxiliary Boiler H_2SO_4 BACT determination will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline-quality NG.

9.1.5 GHG BACT

The following sections present a review of pollutant formation and possible control technologies for GHG emissions from the NG-firing in the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach.

9.1.5.1 Background on Pollutant Formation

See Section 7.6.1. for pollutant formation.

9.1.5.2 Identification of Potential Control Techniques (Step 1)

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

- CCS
- Alternative Fuels-Biomass/Co-firing
- Low Carbon Fuel Source; and
- Good Combustion Practices (refer to Section 7.6.2.2)

9.1.5.3 Elimination of Technically Infeasible Control Options (Step 2)

9.1.5.3.1 CCS

See Section 7.6.3.1 for a complete description of technical infeasibility for the CTs, which are relevant to the Auxiliary Boiler installation.

9.1.5.3.2 Alternative Fuels-Biomass/Co-firing

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Pure biomass fuels include animal meal, waste wood products and sawdust, and sewage sludge. It may also be possible to use biomass materials that are specifically cultivated for fuel use, such as wood, grasses, green algae, and other quick growing species. Gas co-firing involves modification of the combustion system to accommodate the introduction of NG or biomass-derived gas. The co-fired fuel is injected directly into the combustion zone. While co-firing of NG or biofuels does not present any technical issues which cannot be addressed through appropriate design, availability of gaseous biomass-based fuels is limited such that a consistent supply of such fuels cannot be assured over the life of the boiler. In addition, the combustion of biomass-based fuels can affect compliance with BACT limits for other pollutants, such as NO_X and CO. Therefore, the boiler will be constructed and operated to utilize only NG.

Based on the information reviewed for this BACT determination, EKPC has determined that the use of alternative fuels-biomass/co-firing is not a technically feasible option for the Auxiliary Boiler at this source.

9.1.5.3.3 Low Carbon Fuel Use

The Auxiliary Boiler is defined as a NG-fired unit, and thus uses a low carbon fuel. NG has less CO_2 emissions per Btu than any other available fuels.

9.1.5.3.4 Good Combustion Practices

Based on the information reviewed for this BACT determination, EKPC has determined that the use of good combustion practices is a technically feasible option for the Auxiliary Boiler at this source.

9.1.5.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are presented in **Table 9-3**.

Table 9-3. Ranked GHG Control Options

Rank	Control Option	Control Efficiency (%)
1	Low Carbon Fuels	Reduction Varies
2	Good Combustion Practices	Reduction Varies

9.1.5.5 Evaluation of Most Stringent Controls (Step 4)

EKPC has chosen to use NG as a low carbon fuel and will apply good combustion practices.

9.1.5.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. There are no applicable NSPS, NESHAP, or State rules to set the BACT floor for GHG emissions from an auxiliary boiler.

RBLC Review. The RBLC entries for all similarly sized industrial boilers list NG as a low carbon fuel and good combustion practices as the control method.

Selection of BACT. EKPC proposes a CO_2e BACT emission limit of 117.1 lb/MMBtu with compliance demonstrated by combusting pipeline-quality NG, and maintaining and operating the Auxiliary Boiler in accordance with manufacturer's recommendations and 40 CFR 63 Subpart DDDDD.

9.2 Fuel Gas Preheaters and HVAC Heaters

The proposed Fuel Gas Preheaters and HVAC Heaters will be fired with NG. The control technologies listed in the following subsections were obtained from the RBLC database for gas-fired heaters in the size range of the Fuel Gas Preheaters and HVAC Heaters at Cooper Station and from research of emerging technologies. The RBLC search conducted for this analysis was based on RBLC Process Code 13.310 – Commercial/Institutional-Sized Boilers/Furnaces <100 MMBtu/hr over a ten-year period. For the purpose of this analysis, only the entries for heaters firing NG were reviewed.

9.2.1 CO and VOC BACT

The following sections present a review of pollutant formation and possible control technologies for CO and VOC emissions from the Fuel Gas Preheaters and HVAC Heaters. Air pollution control strategies are evaluated using the top-down BACT approach.

9.2.1.1 Background on Pollutant Formation

See Section 8.1.1 for a description on pollutant formation.

9.2.1.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable CO and VOC control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- Oxidation catalyst
- Good combustion practices

Oxidation catalyst and good combustion practices were discussed in Section 7.1 of this application.

9.2.1.3 Elimination of Technically Infeasible Control Options (Step 2)

9.2.1.3.1 Oxidation Catalyst

The results from the RBLC database search do not include oxidation catalyst for CO or VOC BACT compliance. EKPC is not aware of any heaters that have demonstrated the use of such a system and therefore does not consider this technology to meet the "applicable" requirement. For this reason, oxidation catalyst is not technically feasible.

9.2.1.3.2 Good Combustion Practices

Good combustion practices, such as controlling the air/oxygen supply and maintaining an appropriate temperature in the combustion chambers, is included in the baseline design of the proposed project. Therefore, this control method is considered to be technically feasible.

9.2.1.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technology is presented in **Table 9-4**.

Table 9-4. Ranked CO/VOC Control Options

Rank	Control Option	Control Efficiency (%)
1	Good Combustion Practices	Reduction Varies

9.2.1.5 Evaluation of Most Stringent Controls (Step 4)

EKPC has chosen to apply good combustion practices for selecting a BACT emission limit.

9.2.1.6 Selection of BACT (Step 5)

9.2.1.6.1 Selection of CO BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. None of the Fuel Gas Preheaters or HVAC Heaters will be subject to any NSPS, NESHAP, or SIP rules which specify emission limits for CO. As such, there is no floor for an allowable CO BACT limit.

RBLC Review. The proposed CO BACT limit is consistent with the most prevalent emission limits included in the RBLC database, including emission limits from the 2022 and 2023 calendar years.

Selection of BACT. EKPC will reduce CO emissions through the use of good combustion controls, according to the requirements of BACT. For each heater, EKPC is proposing a CO BACT limit of 0.082 lb/MMBtu on a three-hour block average basis. Compliance will be demonstrated through the combustion of pipeline-quality NG, maintaining and operating combustion sources in accordance with manufacturer's recommendations. Given the size and intermittent operation of these units, it is EKPC's position that no source testing is needed.

9.2.1.6.2 Selection of VOC BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. None of the Fuel Gas Preheaters or HVAC Heaters will be subject to any NSPS, NESHAP, or SIP rules which specify emission limits for VOC. As such, there is no floor for an allowable VOC BACT limit.

RBLC Review. The proposed VOC BACT limit is consistent with the most prevalent emission limits included in the RBLC database, including emission limits from the 2022 and 2023 calendar years.

Selection of BACT. EKPC will reduce VOC emissions through the use of good combustion controls, according to the requirements of BACT. For each heater, EKPC is proposing a VOC BACT limit of 0.005 lb/MMBtu on a three-hour block average basis. Compliance will be demonstrated through the combustion of pipeline-quality NG, maintaining and operating combustion sources in accordance with manufacturer's recommendations. Given the size and intermittent operation of these units, it is EKPC's position that no source testing is needed.

9.2.2 NO_X BACT

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the Fuel Gas Preheaters and HVAC Heaters. Air pollution control strategies are evaluated using the top-down BACT approach.

9.2.2.1 Background on Pollutant Formation

See Section 8.2.1 for a description on pollutant formation.

9.2.2.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable NO_X control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- SCR
- SNCR
- Low-NO_X burners
- Good combustion practices

These control technologies were previously described in Sections 7.3 and 8.2.

FGR is generally limited for applications in larger, indirect-fired boilers and process heaters/furnaces where the burner flame zone is accessible for the re-introduction of flue gas. This technology is not available to the Fuel Gas Preheaters or indirect-fired HVAC Heaters and will not be discussed further. Additionally, while available for the Fuel Gas Preheaters, LNBs are not available for the smaller HVAC Heaters and as such are not discussed further in the context of NO_X control from the HVAC Heaters.

9.2.2.3 Elimination of Technically Infeasible Control Options (Step 2)

9.2.2.3.1 SCR and SNCR

As previously stated, the ideal flue gas temperature range for optimal SCR and SNCR operation is 700°F to 750°F. However, the exhaust temperature for each heater is approximately 300°F. Therefore, additional exhaust gas preheaters would be required to raise the temperature by approximately 535°F for the boilers and 300°F for the oil heaters. Since the temperature is not within the required operating range and has not been demonstrated for similar units, neither SCR nor SNCR are a technically feasible control option for reducing NO_X emissions from the heaters.

9.2.2.3.2 Low-NOx Burners

Low-NO_X burners are considered technically feasible for the Fuel Gas preheaters.

9.2.2.3.3 Good Combustion Practices

Good combustion practices are included in EKPC's baseline design and therefore technically feasible.

9.2.2.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are presented in **Table 9-5** in order of control effectiveness.

Table 9-5. Ranked NO_X Control Options – Heaters

Rank	Control Option	Control Efficiency (%)
1	Low-NO_X burners	38%-63%
2	Good combustion practices	Reduction Varies

9.2.2.5 Evaluation of Most Stringent Controls (Step 4)

LNBs are proposed for the Fuel Gas Preheaters based on availability for sources in the proposed size range.

Good combustion practices are included in EKPC's baseline design for the Fuel Gas Preheaters and HVAC Heaters and do not pose any adverse energy, environmental, or economic impacts.

9.2.2.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. None of the Fuel Gas Preheaters or HVAC Heaters will be subject to any NSPS, NESHAP, or SIP rules which specify emission limits for NO_X. As such, there is no floor for an allowable NO_X BACT limit.

RBLC Review. The proposed BACT limits are consistent with the most prevalent emission limits included in the RBLC database, including emission limits from the 2022 and 2023 calendar years.

Selection of BACT. EKPC will reduce NO_X emissions from the Fuel Gas Preheaters through the use of LNBs and good combustion practices, according to the requirements of BACT. EKPC will reduce NOx emissions from the HVAC Heaters through the use of good combustion practices. EKPC proposes the following BACT limits:

- For each Fuel Gas Preheater, EKPC is proposing a BACT limit of 0.05 lb/MMBtu on a three-hour block average basis.
- For the HVAC Heaters, EKPC is proposing a BACT limit of 0.1 lb/MMBtu on a three-hour block average basis.

Compliance will be demonstrated through the combustion of pipeline-quality NG and maintaining and operating combustion sources in accordance with manufacturer's recommendations. Although the RBLC database contains entries with lower emission limits for similar small, NG-fired combustion units, these units are not required to demonstrate compliance through source testing, and in most cases are not designed to allow for direct measurement of emissions. Therefore, little data is available to prove that the units comply with these limits. Given the relatively low emissions from small, NG-fired combustion units, and the uncertainty with respect to the performance of these units, EKPC's proposed emission limits represent BACT-level control.

9.2.3 PM/PM_{10}/$PM_{2.5}$ BACT

The following sections present a review of pollutant formation and possible control technologies for PM, PM_{10}, and $PM_{2.5}$ emissions from the Fuel Gas Preheaters and HVAC Heaters. Air pollution control strategies are evaluated using the top-down BACT approach.

9.2.3.1 Background on Pollutant Formation

See Section 8.3.1 for pollutant formation.

9.2.3.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, potentially applicable PM/PM_{10}/$PM_{2.5}$ control technologies for NG-fired heaters were identified. The available control options are combustion design controls and use of low sulfur fuel to mitigation CPM formation..

9.2.3.3 Elimination of Technically Infeasible Control Options (Step 2)

All options identified in Step 1 are technically feasible.

9.2.3.4 Rank of Remaining Control Technologies (Step 3)

Implementing combustion design controls and use of low sulfur fuel provides the most effective means for reducing emissions of PM/PM_{10}/$PM_{2.5}$ from the heaters.

9.2.3.5 Evaluation of Most Stringent Controls (Step 4)

The top and only available and technically feasible PM control options are be applied to achieve compliance with the proposed BACT limit.

9.2.3.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Fuel Gas Preheater serving C2 (EU17) will be subject to NSPS Subpart Dc, which does not have a PM emission limit for NG-fired boilers.

All three Fuel Gas Preheaters (EU17, EU23, and EU24) meet the definition of indirect heat exchangers under 401 KAR 59:015 and are affected facilities. 401 KAR 59:015 lists a PM emission limit of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)], and as such, the state rule sets the BACT floor.

RBLC Review. Based on review of the RBLC database, EKPC believes that the proposed PM, PM_{10}, and $PM_{2.5}$ BACT limit is consistent with established limits for comparable NG heaters.

Selection of BACT. EKPC proposes good combustion practices and combustion of pipeline-quality NG as BACT for PM. Compliance with the Fuel Gas Preheaters and HVAC Heaters PM BACT determination will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline-quality NG.

9.2.4 H_2SO_4 BACT

The following sections present a review of pollutant formation and possible control technologies for H_2SO_4 emissions from the Fuel Gas Preheaters and HVAC Heaters. Air pollution control strategies are evaluated using the top-down BACT approach.

9.2.4.1 Background on Pollutant Formation

See Section 3.1.1.1.1 for an explanation on pollutant formation.

9.2.4.2 Identification of Potential Control Techniques (Step 1)

H_2SO_4 emissions are generally controlled through the use of low-sulfur fuels or with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. Based on the emission limits included in the RBLC database, add-on control equipment for reduction of H_2SO_4 emissions from small, NG-fired combustion sources has not been demonstrated, and is therefore not an available control. The only available control option for reduction of H_2SO_4 emissions is the use of Fuel Specifications, or combustion of low sulfur fuels.

9.2.4.3 Elimination of Technically Infeasible Control Options (Step 2)

Combusting only clean NG, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with NG has a very low potential for generating H_2SO_4 emissions. Fuel specifications is included in RBLC for the control of H_2SO_4 emissions from heaters.

Based on the information reviewed for this BACT determination, EKPC has determined that the use of fuel specifications is a technically feasible option for the heaters at this source.

9.2.4.4 Rank of Remaining Control Technologies (Step 3)

The only measure identified for control of H_2SO_4 resulting from the operation of the heaters is the use of fuel specifications.

9.2.4.5 Evaluation of Most Stringent Controls (Step 4)

The top and only available and technically feasible H_2SO_4 control option will be applied to achieve compliance with the proposed BACT limit.

9.2.4.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. There are no applicable NSPS, NESHAP, or State rules to set the BACT floor for H_2SO_4 emissions from the heaters.

RBLC Review. Similarly sized NG-fired heaters list combustion of clean/low-sulfur fuel as the control method.

Selection of BACT. EKPC proposes combustion of pipeline-quality NG as BACT for H_2SO_4. Compliance with the H_2SO_4 BACT limit will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline-quality NG.

9.2.5 GHG BACT

The following sections present a review of pollutant formation and possible control technologies for GHG emissions from the Fuel Gas Preheaters and HVAC Heaters. Air pollution control strategies are evaluated using the top-down BACT approach.

9.2.5.1 Background on Pollutant Formation

See Section 7.6.1. for pollutant formation.

9.2.5.2 Identification of Potential Control Techniques (Step 1)

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. This BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

- CCS
- Low Carbon Fuel Source; and
- Good Combustion Practices (refer to Section 7.6.2.2)

9.2.5.3 Elimination of Technically Infeasible Control Options (Step 2)

Refer to Section 7.6.3.1 for a complete description of technical infeasibility for CCS applicable to the CTs, which are relevant to the Fuel Gas Preheaters and HVAC Heaters installation. Use of NG as a low carbon fuel and good combustion practices for small, NG-fired heaters are technically feasible.

9.2.5.4 Rank of Remaining Control Technologies (Step 3)

Use of NG as a low carbon fuel and good combustion practices for small, NG-fired heaters are selected.

9.2.5.5 Evaluation of Most Stringent Controls (Step 4)

EKPC has chosen to use NG as a low carbon fuel and will apply good combustion practices.

9.2.5.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. There are no applicable NSPS, NESHAP, or State rules to set the BACT floor for GHG emissions from the heaters.

RBLC Review. The RBLC entries for all similarly sized fuel gas heaters list NG as a low carbon fuel and good combustion practices as the control method.

Selection of BACT. EKPC proposes a CO_2e BACT emission limit for all preheaters and HVAC heaters of 117.1 lb/MMBtu with compliance demonstrated by combusting pipeline NG. CO_2e emissions from the heaters shall be controlled through the use of good combustion practices.

9.3 Internal Combustion Engine BACT Analysis

Two diesel fired emergency engines will be used in the proposed facility – one (1) in the emergency fire suppression system and one (1) in an emergency generator. The fire pump engine will be a NFPA certified nominal 310 hp compression ignition fire pump engine and will be run on ULSFO, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). The generator engine will be nominal 1,250 kW (2,200 bhp) compression ignition engine and will be run on ULSFO, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). Combustion of the ULSFO will yield emissions of CO, VOC, NO_X, PM, PM_{10}, $PM_{2.5}$, and GHG.

The RBLC searches conducted for this analysis were based on RBLC Process Code 17.110 – Large Internal Combustion Engines >500 HP, and RBLC Process Code 17.210 – Small Internal Combustion Engines <500 HP. The RBLC searches were performed over a ten-year period. For the purpose of this analysis, only the entries for ICE firing ULSFO were reviewed.

9.3.1 CO and VOC BACT

The following sections present a review of pollutant formation and possible control technologies for CO and VOC emissions from CI ICE. Air pollution control strategies are evaluated using the top-down BACT approach.

9.3.1.1 Background on Pollutant Formation

See Section 8.1.1 for a description on pollutant formation.

9.3.1.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable CO and VOC control technologies were identified based on the principles of the control technology and engineering experience for CI ICE. These technologies are listed as follows:

- Diesel Oxidation Catalyst (DOC)
- Combustion Design Controls

The DOC unit is a commonly used “flow through” control device for stationary diesel engines which contains a honeycomb-like structure or substrate with a large surface area that is coated with an active catalyst layer reduces emissions of CO and VOC. CO, gaseous hydrocarbons and liquid hydrocarbon particles (unburned fuel and oil) in the exhaust gas are oxidized to CO_2 and H_2O. The reduction of CO and VOC varies depending on the catalyst formulations in the DOC.[134]

9.3.1.3 Elimination of Technically Infeasible Control Options (Step 2)

Although DOC is technically feasible, this technology may not provide consistent CO and VOC control efficiencies and may be difficult to operate when used to reduce CO and VOC emissions from sources that operate intermittently like these emergency engines. Since it can take time for the exhaust stream to reach the required operating temperature range for efficient oxidation, the CO and VOC CE of DOC for an engine is lower than for a unit that runs at steady-state. Except for emergencies, the engines will typically operate intermittently to perform readiness testing and maintenance checks that occur no more than weekly.

Combustion design controls are a technically feasible control option for reducing CO and VOC emissions from CI ICE.

9.3.1.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technologies are presented in **Table 9-6** in order of control effectiveness.

[134] EPA Final Report, Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010.

Table 9-6. Remaining CO and VOC Control Technologies – Emergency Engines

Rank	Control Technology	Potential Control Efficiency (%)
1	DOC	Up to 90% for CO and VOC
2	Combustion Design Controls	Reduction Varies

Catalytic/thermal oxidation provides the most effective means for achieving CO and VOC emissions reductions followed by implementing combustion design controls.

9.3.1.5 Evaluation of Most Stringent Controls (Step 4)

EPA determined in the development of NSPS Subpart IIII and NESHAP Subpart ZZZZ that add-on controls are not cost effective for emergency ICE.[135] [136]As such, the implementation of thermal or catalytic oxidation is not cost effective.

EKPC has determined that the top and only remaining available and technically feasible CO and VOC control option, combustion design controls, will be applied to achieve compliance with the proposed BACT limit.

9.3.1.6 Selection of BACT (Step 5)

9.3.1.6.1 Selection of CO BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for CO. As such, NSPS IIII sets the floor for an allowable CO BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, EKPC believes that the proposed CO BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. EKPC proposes a CO BACT emission limit for the fire pump equal to that of the applicable NSPS IIII standard, or 2.6 g/bhp-hr.[137] EKPC proposes a CO BACT emission limit for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 2.6 g /bhp-hr.[138]

To comply with the proposed CO BACT limits, EKPC will purchase engines certified by the manufacturers to meet these emission levels. Operation of the ICE for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance) will be limited to

[135] EPA Office of Air Quality Planning and Standards, *Regulatory Impact Analysis of the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines,* EPA-452/R-06-003, June 2006

[136] EPA Office of Air Quality Planning and Standards, *Regulatory Impact Analysis (RIA) for the Reconsideration of the Existing Stationary Compression Ignition (CI) Engines NESHAP – Final Report*, EPA-452/R-13-001, January 2013

[137] Pursuant to §60.4205(c), the fire pump engines (which have a displacement less than 30 liters per cylinder) are subject to the emission limits from Table 4 of Subpart IIII.

[138] Pursuant to §60.4205(b), the emergency engines (which have a displacement less than 30 liters per cylinder) are subject to the corresponding Tier emission limits from Appendix I to Part 1039.

100 hours per year (each engine). The total annual hours of operation for the ICE including periods of operation at full loads for emergency use are expected to be less than 500 hours (each engine).

9.3.1.6.2 Selection of VOC BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for VOC in the form of a combined NO_X + NMHC emission limit. As such, NSPS IIII sets the floor for an allowable VOC BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, EKPC believes that the proposed VOC BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. EKPC proposes a combined BACT emission limit for NO_X and NMHC for the fire pump equal to that of the applicable NSPS IIII standard, or 3.0 g/hp-hr. EKPC proposes a combined BACT emission limit for NO_X and NMHC for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 4.8 g/hp-hr.

To comply with the proposed VOC BACT limits, EKPC will purchase engines certified by the manufacturers to meet these emission levels. Operation of the ICE for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance) will be limited to 100 hours per year (each engine). The total annual hours of operation for the ICE including periods of operation at full loads for emergency use are expected to be less than 500 hours (each engine).

9.3.2 NO_X BACT

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the CI ICE. Air pollution control strategies are evaluated using the top-down BACT approach.

9.3.2.1 Background on Pollutant Formation

See Section 8.2.1 for a description on pollutant formation.

9.3.2.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable NO_X control technologies were identified based on the principles of the control technology and engineering experience for internal combustion engines. These technologies are listed as follows:

- SCR
- SNCR
- Combustion Design Controls

SCR and SNCR were discussed in detail in previous sections of the application. Applying SNCR and SCR to the diesel engines at the facility may be challenging from an operations standpoint due to the varying conditions of the exhaust. The NO_X emission rate from the engines will vary during startup and depend upon the operating conditions of the engine. Under these conditions, an SCR or SNCR unit would not be capable of achieving steady-state operation and would pose adverse environmental impacts due to ammonia slip or urea release. SCR and SNCR will not be discussed further in this section.

9.3.2.3 Elimination of Technically Infeasible Control Options (Step 2)

Combustion design controls are a technically feasible option for reducing NO_X emissions from CI ICE.

9.3.2.4 Rank of Remaining Control Technologies (Step 3)

Combustion design controls are a technically feasible option for reducing NO_X emissions from CI ICE.

9.3.2.5 Evaluation of Most Stringent Controls (Step 4)

Combustion design controls will be applied to achieve compliance with the proposed BACT limits.

9.3.2.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for NO_X in the form of a combined limit for NO_X + NMHC. As such, NSPS IIII sets the floor for an allowable NO_X BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, EKPC believes that the proposed NO_X BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. As previously stated, EKPC proposes a combined BACT emission limit for NO_X and NMHC for the fire pump equal to that of the applicable NSPS IIII standard, or 3.0 g/hp-hr. EKPC proposes a combined BACT emission limit for NO_X and NMHC for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 4.8 g/hp-hr.

To comply with the proposed NO_X BACT limits, EKPC will purchase emergency engines certified by the manufacturers to meet these emissions levels. Operation of the engines for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year (each engine) and the total annual hours of operation including emergency use will be limited to 500 hours per year (each engine).

9.3.3 PM/PM_{10}/$PM_{2.5}$ BACT

The following sections present a review of pollutant formation and possible control technologies for particulate emissions from the CI ICE. Air pollution control strategies are evaluated using the top-down BACT approach.

9.3.3.1 Background on Pollutant Formation

See Section 8.3.1 for pollutant formation.

9.3.3.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable PM control technologies were identified based on the principles of the control technology and engineering experience for CI ICE. These technologies are listed as follows:

- Catalyzed Diesel Particulate Filter (CDPF)
- Combustion Design Controls

- Usage of Clean Fuels

9.3.3.3 Elimination of Technically Infeasible Control Options (Step 2)

All controls options are technically feasible control options for reducing PM emissions from diesel engines. Therefore, no control options are eliminated in this step of the analysis.

9.3.3.4 Rank of Remaining Control Technologies (Step 3)

Particulate filters provide the most effective means for reducing PM emissions from ICEs with a CE of up to 94 percent depending on the size of the engine.[139] Implementing combustion design controls, and usage of clean fuels are the next most effective control option for reducing PM emissions.

9.3.3.5 Evaluation of Most Stringent Control Technologies (Step 4)

As previously stated, EPA determined in the development of NSPS Subpart IIII that add-on controls are not cost effective for emergency ICE. Based on EPA's economic analysis, EKPC has determined that CDPF is not BACT for PM emissions from the diesel engines.

With CDPF eliminated, combustion design controls and usage of clean fuels are the remaining available and technically feasible PM control options will be applied to achieve compliance with the proposed BACT limit.

9.3.3.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for filterable PM. As such, NSPS IIII sets the floor for an allowable filterable PM BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, EKPC believes that the proposed filterable PM BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. EKPC proposes a filterable PM BACT emission limit for the fire pump equal to that of the applicable NSPS IIII standard, or 0.15 g/bhp-hr. EKPC proposes a filterable PM BACT emission limit for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 0.15 g/bhp-hr. EKPC proposes ULSFO for CPM BACT.

To comply with the proposed PM filterable BACT limits, EKPC will purchase engines certified by the manufacturers to meet these emissions levels and will use ULSFO. Operation of the engines for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year (each engine) and the total annual hours of operation including emergency use will be limited to 500 hours per year (each engine).

9.3.4 GHG BACT

The following sections present a review of pollutant formation and possible control technologies for GHG emissions from the CI ICE. Air pollution control strategies are evaluated using the top-down BACT approach.

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[139] Memo from Ms, Tanya Parise, Alpha Gamma Technologies, Inc. to Mr. Sims Roy, U.S. EPA OAQPS ESD Combustion Group. *Cost per Ton for NSPS for Stationary CI ICE*. June 9, 2005.

9.3.4.1 Background on Pollutant Formation

See Section 7.6.1. for pollutant formation.

9.3.4.2 Identification of Potential Control Techniques (Step 1)

Based on a review of technical literature, past control technology determinations, and generally available technologies and practices, the following options could potentially be applied to control GHG emissions from EKPC's diesel combustion equipment:

- Fuel Selection
- Good Design and Operating Practices

CCS is not an available GHG control option for the emergency engines.

9.3.4.2.1 Fuel Selection

The carbon intensity of fuels can vary significantly across available fossil fuels commonly used in industry. Fuels with low carbon intensity have lower GHG emissions than fuels with high carbon intensity. Therefore, GHG BACT considerations involve the evaluation of low carbon intensity fuel options. By selecting a low carbon fuel, GHG emissions are minimized. Diesel is the standard fuel type for this emergency equipment, given its ease of handling and storage, its suitability for use in emergency equipment with highly variable operations, and its prevalence of use in engine technology. The ability for the on-board storage of diesel with the engine ensures fuel availability when it is needed.

9.3.4.2.2 Good Design and Operating Practices

Good design and operating practices for controlling GHG emissions from diesel-fired engines consist of minimizing startup and idling time, in addition to good air to fuel mixing to promote complete combustion. By operating a combustion unit as efficiently as possible, GHG emissions are minimized. This is achieved in normal practice for emergency-use engines that, by design, only operate for maintenance purposes, readiness testing, and during emergency events.

9.3.4.3 Elimination of Technically Infeasible Control Options (Step 2)

EKPC has selected ULSFO and will implement good combustion design and operating practices on each diesel-fired emergency engine. The various unit vendors have implemented design elements that promote complete combustion and efficiency. As such, these good operating practices include the optimization of energy efficiency.

9.3.4.4 Rank of Remaining Control Technologies (Step 3)

Use of diesel and good design and operating practices are normal practice for emergency-use engines, so no additional GHG reduction can be attributed.

9.3.4.5 Evaluation of Most Stringent Control Technologies (Step 4)

For emergency equipment, GHG BACT considerations will include optimum engine efficiency and good design and operating practices for the diesel-fired engines. There are no significant economic, environmental, or energy impacts associated with the selected control methods.

9.3.4.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. There are no applicable NSPS, NESHAP, or State rules to set the BACT floor for GHG emissions from a CI ICE.

RBLC Review. No similar facilities or facilities with similar process types were identified in the RBLC as using any type of add-on control device. This finding bolsters the conclusion that BACT should be represented by emission limits that do not account for the implementation of an add-on control device.

Selection of BACT. EKPC proposes to operate the emergency diesel engines in accordance with good combustion and operating practices to achieve compliance with the following GHG BACT limit:

- 163 lb/MMBtu CO_2e for the emergency generator and emergency fire pump engines

With no add-on controls available, the only effective methods of reducing GHG emissions are the selection of energy efficient diesel-fired engines and the implementation of good combustion, operating, and maintenance practices to minimize GHG emissions. Compliance with the proposed GHG BACT limit for the emergency diesel engines will be demonstrated by using ULSFO and purchasing a certified engine.

9.4 Cooling Towers

The cooling towers are multi-cell, mechanical induced draft cooling towers that will be used to reject heat from cooling water for the condensate system and other plant uses, and will be sources of filterable PM emissions. The RBLC search conducted for this analysis was based on RBLC Process Code 99.009 – Miscellaneous Sources, Industrial Process Cooling Towers over a ten-year period.

9.4.1 Background on Pollutant Formation

Filterable PM is emitted from wet cooling towers because the water circulating in the tower contains small amounts of dissolved solids (e.g., calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower; however, drift eliminator technology reduce the potential for cooling tower drift.

9.4.2 Identification of Potential Control Techniques (Step 1)

Potentially available control options for reducing PM emissions from mechanical draft wet cooling towers include options to minimize dissolved solids in the cooling water and add-on controls such as advanced drift eliminators.

As discussed in the cooling tower research paper used as the basis for the PM_{10} and $PM_{2.5}$ particle size multipliers referenced in **Appendix B**, the fraction of PM emitted as PM_{10} and $PM_{2.5}$ is primarily a function of the drift droplet size distribution.[140] The drift droplet size distribution from a mechanical draft cooling tower can vary based on fill design, the air and water flow patterns within the tower, frequency of tower maintenance, and operating levels.[141] Based on this complex interaction between cooling tower design and operating characteristics and the fact that U.S. EPA has not promulgated an approved test method for

[140] Joel Reisman and Gordon Frisbie, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Environmental Progress, Vol. 21 Iss. 2 pgs. 127-130, April 20, 2004.

[141] U.S. EPA, Document Number AP-42, Compilation of Air Pollution Emission Factors, Vol. 1 Stationary and Area Sources, Chapter13: Miscellaneous Sources, Section 13.4 Wet Cooling Towers, 5th Edition, pp. 13.4-1 to 13.4-6.

measuring PM emissions in cooling tower drift, no cooling tower control options specifically targeting PM_{10} or $PM_{2.5}$ removal were identified. Drift eliminators do, however, reduce drift formation which in turn reduces all size fractions of PM emissions.

9.4.3 Elimination of Technically Infeasible Control Technologies (Step 2)

All control options identified are technically feasible.

9.4.4 Rank of Remaining Control Technologies (Step 3)

Utilizing drift (mist) eliminators and minimizing dissolved solids in the circulating water are the only technically feasible control options for reducing PM/PM_{10}/$PM_{2.5}$ emissions from the cooling towers. Modern wet cooling towers with advanced drift eliminators generally achieve a drift rate of less than or equal to 0.0005 percent.

9.4.5 Evaluation of Most Stringent Control Technologies (Step 4)

The top and only available and technically feasible PM/PM_{10}/$PM_{2.5}$ control options will be applied to achieve compliance with the proposed BACT limit. The environmental, energy, and economic impacts of drift eliminators and minimizing dissolved solids are insignificant.

9.4.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. As discussed in Section 5.7.3, the mechanical draft cooling tower will be subject to 401 KAR 59:010, which sets a process weight rate-based PM emissions limit. As such, the state rule sets the BACT floor.

RBLC Review. All modern wet cooling towers are equipped with drift (mist) eliminators. This control option is designated as BACT for each cooling tower in the RBLC as shown in **Appendix D.**

Selection of BACT. EKPC is proposing to utilize drift eliminators for the proposed mechanical cooling with a 0.0005 percent drift rate. This drift rate is consistent with other recent BACT determinations. To demonstrate compliance with the proposed PM/PM_{10}/$PM_{2.5}$ BACT limits, EKPC will purchase high efficiency drift eliminators designed to achieve a drift rate of less than 0.0005 percent of the circulating water flow rate.

9.5 Storage Tanks VOC BACT Analysis

EKPC will operate one 1,000 gallon ULSFO storage tank for the emergency generator, one 350 gallon ULSFO storage tank for the fire pump, and two 1.66 MMgal ULSFO storage tanks for both CCGTs. Based on the EKPC usage rates, the annual throughput of the generator storage tank is 45,888 gallons per year, the annual throughput of the fire pump storage tank is 7,966 gallons per year, and the annual throughput of the CCGT storage tanks is 21,280,800 gallons per year (each tank). Because the maximum true vapor pressure of the ULSFO of each tank is less than 0.25 psia, the tanks are exempt from the tank design requirements in NSPS Subpart Kc. Therefore, there are no applicable NSPS to provide a baseline for the BACT analysis.

The annual potential emission rate from the generator storage tank is 5.22 E-4 tpy, the annual potential emission rate from the fire pump storage tank is 1.21 E-4 tpy, and the annual potential emission rates for each CCGT storage tank is 0.41 tpy. No control options are available for reducing VOC emissions from these tanks given the low concentration of emissions. Therefore, a full top down BACT analysis is not warranted. EKPC proposes that there be no emission limit or monitoring required for the storage tanks at the facility.

9.6 Sulfuric Acid Tank BACT Analysis

EKPC will operate one 3,000 gallon 93% sulfuric acid storage tank Based on expected plant-wide consumption rates, the annual throughput of this storage tank is 20,000 gallons per year. There are no applicable NSPS to provide a baseline for the BACT analysis.

The annual potential H_2SO_4 emission rate from the sulfuric acid storage tank is 1.46 E-7 tpy. No control options are available for reducing H_2SO_4 emissions from this tank given the low concentration of emissions. Therefore, a full top down BACT analysis is not warranted. EKPC proposes that there be no emission limit or monitoring required for the sulfuric acid storage tank at the facility.

9.7 Plant Roads

Fugitive PM emissions due to increased vehicle movement on the existing and new plant roads are expected as part of this project. The RBLC search conducted for this analysis was based on RBLC Process Code 99.140 – Miscellaneous Sources, Paved Road over a ten-year period.

9.7.1 Background on Pollutant Formation

Fugitive PM emissions from vehicle movement across paved roads are primarily generated from resuspension of loose material on the road surface.

9.7.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable PM control technologies were identified based on the principles of the control technology and engineering experience for controlling fugitive emissions from paved roads. These technologies are listed as follows:

- Paving roadways
- Sweeping roadways
- Wet or chemical suppression
- Good housekeeping

9.7.3 Elimination of Technically Infeasible Control Options (Step 2)

All control options identified are technically feasible. Therefore, no control options are eliminated in this step of the analysis.

9.7.4 Rank of Remaining Control Technologies (Step 3)

The emission reductions from all remaining control technologies vary. The control technologies are rated as follows:

- Paving roads reduces fugitive emissions from road dust versus leaving the roads unpaved
- Sweeping paved roads will limit dust fugitive emissions
- Wet suppression systems can be used on either paved or unpaved roads
- Good housekeeping practices will minimize dust fugitive emissions

9.7.5 Evaluation of Most Stringent Control Technologies (Step 4)

All four options are technically feasible $PM/PM_{10}/PM_{2.5}$ control options and will be applied to achieve compliance with the proposed work practice BACT limit.

9.7.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. As discussed in Section 5.7.6, the paved roads will be subject to 401 KAR 63:010; however, this state rule does not set a defined fugitive PM emissions limit. As such, there are no applicable NSPS, NESHAP, or SIP rules to set the BACT floor for filterable PM emissions from the paved roads.

RBLC Review. The proposed BACT limits are consistent with the most prevalent control methods included in the RBLC database.

Selection of BACT. All new roads associated with this project will be paved and the plant will use best management practices (BMP) (e.g. road paving, sweeping, wet suppression systems and good housekeeping practices, etc.) to minimize fugitive dust emissions due to road traffic. EKPC will prepare an appropriate dust control plan and will utilize water or chemical suppression on an as needed basis to control dust emissions and will post speed limit signs. Records of control measures taken under the fugitive dust program will be maintained to demonstrate compliance.

9.8 Equipment Leaks – NG Piping Components

The project will result in fugitive VOC and GHG emissions from equipment leaks from the new NG piping components. The RBLC search conducted for this analysis was based on the following RBLC Process Codes over a ten-year period:

- 50.002 (Petroleum/Natural Gas Production and Refining, Natural Gas/Gasoline Processing Plants)
- 50.007 (Petroleum/Natural Gas Production and Refining, Petroleum Refining Conversion Processes)
- 50.999 (Petroleum/Natural Gas Production and Refining, Other Petroleum/Natural Gas Production & Refining Sources)

9.8.1 Background on Pollutant Formation

As NG is transmitted past the various new NG piping components to be installed as part of the Cooper Project, emissions occur through unintentional leaks from connections between pipes, and to valves/other equipment. As described in Section 3.3.7, the NG stream is primarily methane but is also composed of smaller concentrations of VOC and CO_2.

9.8.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable VOC and CO_2e control options were identified based on the principles of the control technology and engineering experience for equipment leak components. These technologies are listed as follows:

- Component type/design
- Leak inspections (LDAR or AVO)
- Low-leaking components

9.8.3 Elimination of Technically Infeasible Control Options (Step 2)

An LDAR program is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fittings, sampling connections, and any other connections that could possibly leak in a process. LDAR is secondary to component type/design to minimize the potential for component leaks. LDAR is a work practice that is used to identify leaking equipment so the emissions can be reduced through systematic repair or replacement. The key to an effective program is regularly scheduled inspections and a defined repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC and GHG emissions at this source. AVO inspections provide a simplified method of leak detection through visual scanning for signs of leaks, listening for unusual sounds, and smelling for any NG odor.

9.8.4 Rank of Remaining Control Technologies (Step 3)

A combination of component type/design using low-leaking components, and LDAR or AVO inspections are the only available technologies.

9.8.5 Evaluation of Most Stringent Control Technologies (Step 4)

Component type/design, using low-leaking components, and leak inspections are considered the most effective control available to reduce the occurrence of fugitive emissions. Although LDAR is an available option, given the very low level of emissions and small number of fugitive piping components, the implementation of an LDAR program is cost prohibitive.

9.8.6 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fugitive emissions from NG piping components are not subject to any NSPS, NESHAP, or state rules. As such, there is no floor for an allowable VOC or CO_2e limit.

RBLC Review. The proposed BACT limits are consistent with the most prevalent control methods included in the RBLC database.

Selection of BACT. EKPC has determined that a combination of component type/design using low-leaking components and AVO inspections are BACT for the control of VOC and GHG emissions from equipment leaks from the new piping components. Compliance with this BACT limit will be demonstrated through recordkeeping of AVO inspection activities.

Table 9-7. Equipment Leak Limits

EU ID	EU Name	VOC Limit (tpy)	CO_2e Limit (tpy)
33	NG Piping Fugitives	0.42	919

9.9 Equipment Leaks – Circuit Breakers

The project will result in fugitive GHG emissions from equipment leaks from the turbine circuit breakers and substation circuit breakers. The turbine circuit breakers will be rated at 20 kV, and the substation circuit breakers will be rated at 170 kV. These circuit breakers contain SF_6, which is a greenhouse gas, as an insulator.

While the electrical equipment containing SF_6 is designed not to leak, a BACT analysis for GHG has been performed to address any potential leaks that would cause SF_6 to be emitted.

9.9.1 Steps 1-4 Circuit Breaker GHG BACT Analysis

The only applicable control technology for circuit breakers containing SF_6 is minimization of leaks. This is accomplished using enclosed circuit breaker technology with a leak detection system and an alarm to indicate the presence of a leak or leaks. The use of alternate, non-GHG circuit breaker insulating material is not yet commercially available for this application.

Non-GHG insulating material can be technically feasible for certain applications, and is available for use in lower-voltage circuit breaker configurations. General Electric, Hitachi Energy Switzerland Ltd. and Siemens Energy have developed SF_6-free circuit breaker technology. GE has this technology available for applications up to 145 kV, Siemens up to 72.5 kV, and Hitachi has developed SF_6-free circuit breakers for use in 72.5 kV, 145 kV, and 420 kV applications (the Hitachi technology does not contain SF_6 but it is not GHG-free as it contains some CO_2). Therefore, the only GHG-free technologies currently available are for circuit breakers with a rating lower than the 170 kV proposed by EKPC at Cooper Station. The Hitachi technology, while not GHG-free, is only available for 50 Hz International Electrotechnical Commission (IEC) configuration and is not compatible with the 60 Hz electrical standard in the United States.[142] For the smaller 20 kV turbine circuit breakers, the SF_6-based insulators were directly selected by the turbine vendor, and this technology option is the only available solution for this specific application.

9.9.2 Selection of BACT (Step 5)

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fugitive emissions from the circuit breakers are not subject to any NSPS, NESHAP, or state rules. As such, there is no floor for an allowable CO_2e limit.

RBLC Review. The proposed BACT limits are consistent with the most prevalent control methods included in the RBLC database.

Selection of BACT. EKPC has determined that a maximum allowable leak rate of 0.5% SF_6 monitored by a leak detection system is BACT for the control of GHG emissions from equipment leaks from the circuit breakers. Compliance with this BACT limit will be demonstrated by maintaining records of the parameters monitored by the leak detection system and installation of a low leak circuit breaker system design.

142 Eastern Research Group, Inc. (ERG), *Assessment of the Use of Sulfur Hexafluoride (SF6) Gas Insulated Switchgears (GIS) within the Offshore Wind Sector*, August 24, 2023.

10. SUMMARY OF BACT DETERMINATIONS

A top-down BACT analysis is required for each proposed emission unit emitting a pollutant for which PSD permitting requirements are triggered (NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, H_2SO_4, and GHG). Detailed NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, H_2SO_4, and GHG BACT determinations for the primary emission sources included in the project scope are presented in **Sections 7** through **9** of this application, alongside the detailed "top-down" BACT analysis for each source for the six (6) pollutant groupings. The tables in this section summarize the BACT determinations for each pollutant and source.

Table 10-1. Summary of CT (EU18 and EU19) BACT Determinations

Pollutant	Fuel	BACT Emission Limit (Each Turbine)		BACT Control Type	Compliance Demonstration Method
		Value	Units		
NO_X (Excludes SUSD)	NG	2.0	ppmvd @ 15% O_2 30-day avg	• SCR	• CEMS
NO_X (Excludes SUSD)	ULSFO	4.5	ppmvd @ 15% O_2 30-day avg	• SCR	• CEMS
NO_X (Includes SUSD)	Both	165	tpy, annual avg	• N/A	• CEMS, 12-month rolling calculations
CO (Excludes SUSD)	NG	2.0	ppmvd @ 15% O_2 30-day avg	• Oxidation Catalyst	• CEMS
CO (Excludes SUSD)	ULSFO	2.0	ppmvd @ 15% O_2 30-day avg	• Oxidation Catalyst	• CEMS
CO (Includes SUSD)	Both	2,390 tpy	tpy, annual avg	• N/A	• CEMS, 12-month rolling calculations
VOC (Excludes SUSD)	NG	1.0	ppmvd @ 15% O_2 3-hr avg	• Oxidation catalyst	• Performance test
VOC (Excludes SUSD)	ULSFO	1.0	ppmvd @ 15% O_2 3-hr avg	• Oxidation catalyst	• Performance test
VOC (Includes SUSD)	Both	226	tpy, annual avg	• N/A	• 12-month rolling calculations
$PM/PM_{10}/PM_{2.5}$	NG	17.21[143]	lb/hr, 3-hr avg	• Low Sulfur Fuel and GCOP	• Performance test
$PM/PM_{10}/PM_{2.5}$	ULSFO	30.12[144]	lb/hr, 3-hr avg	• Low Sulfur Fuel and GCOP	• Performance test
H_2SO_4	NG	0.5	gr S/100 scf	• Low Sulfur Fuel and GCOP	• Fuel specification
H_2SO_4	ULSFO	15	ppm total Sulfur	• Low Sulfur Fuel and GCOP	• Fuel specification

[143] Includes both filterable and condensable species.

[144] Inclues both filterable and condensable species.

Pollutant	Fuel	BACT Emission Limit (Each Turbine)		BACT Control Type	Compliance Demonstration Method
		Value	Units		
CO_2	NG	800	lb/MWh-g	• GCOP	• Part 75 Procedures
CO_2	ULSFO	1,250	lb/MWh-g	• GCOP	• Part 75 Procedures

Table 10-2. Summary of C2 Boiler (EU02) BACT Determinations

Pollutant	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
	Value	Units		
NO_X	0.080	lb/MMBtu 30-day avg	• SCR	• CEMS
CO (Excludes SUSD)	0.12	lb/MMBtu 3-hr avg	• GCOP	• Performance test
CO (SUSD)	N/A	N/A	• GCOP	• Comply with 401 KAR 61:015, Section 9
VOC (Excludes SUSD)	0.0055	lb/MMBtu 3-hr avg	• GCOP	• Performance test
VOC (SUSD)	N/A	N/A	• GCOP	• Comply with 401 KAR 61:015, Section 9
FPM + CPM (Excludes SUSD)	0.030	lb/MMBtu 3-hr avg	• CDS and PJFF	• Performance test
$PM/PM_{10}/PM_{2.5}$ (SUSD)	N/A	N/A	• CDS and PJFF	• Comply with 401 KAR 61:015, Section 9
H_2SO_4 (Excludes SUSD)	0.005	lb/MMBtu 3-hr avg	• CDS and PJFF for Co-firing and Low Sulfur Fuel for NG	• Performance test
H_2SO_4 (SUSD)	N/A	N/A	• CDS and PJFF for Co-firing and Low Sulfur Fuel for NG	• Comply with 401 KAR 61:015, Section 9
CO_2	2,074	lb/MWh-g 12-mo rolling	• NG/coal co-firing • GCOP	• Part 75 Procedures

Table 10-3. Summary of Auxiliary Boiler (EU20) BACT Determinations

Pollutant	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
	Value	Units		
NO_X	0.011	lb/MMBtu 3-hr avg	• ULNB and GCOP	• Performance test
CO	0.003	lb/MMBtu 3-hr avg	• Oxidation catalyst and GCOP	• Performance test
VOC	0.0054	lb/MMBtu 3-hr avg	• Oxidation catalyst and GCOP	• Use of oxidation catalyst and GCOP
$PM/PM_{10}/PM_{2.5}$	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Fuel specification
H_2SO_4	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Fuel specification
CO_2e	117.1	lb/MMBtu	• Fuel selection • GCOP	• Use of permitted fuel and GCOP

Table 10-4. Summary of Dewpoint Heaters (EU17, 23, and 24) BACT Determinations

Pollutant	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
	Value	Units		
NO_X	0.05	lb/MMBtu 3-hr avg	• LNB and GCOP	• Use of LNB and GCOP
CO	0.082	lb/MMBtu 3-hr avg	• GCOP	• Use of GCOP
VOC	0.005	lb/MMBtu 3-hr avg	• GCOP	• Use of GCOP
$PM/PM_{10}/PM_{2.5}$	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Use of permitted fuel and GCOP
H_2SO_4	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Use of permitted fuel and GCOP
CO_2e	117.1	lb/MMBtu	• Fuel selection • GCOP	• Use of permitted fuel and GCOP

Table 10-5. Summary of HVAC Unit (EU29A and 29B) BACT Determinations

Pollutant	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
	Value	Units		
NO_X	0.1	lb/MMBtu, 3-hr avg	• GCOP	• Use of GCOP
CO	0.082	lb/MMBtu, 3-hr avg	• GCOP	• Use of GCOP
VOC	0.005	lb/MMBtu, 3-hr avg	• GCOP	• Use of GCOP
$PM/PM_{10}/PM_{2.5}$	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Use of permitted fuel and GCOP
H_2SO_4	0.5	gr/100 scf	• Pipeline quality NG and GCOP	• Use of permitted fuel and GCOP
CO_2e	117.1	lb/MMBtu, 3-hr avg	• Fuel selection and GCOP	• Use of permitted fuel and GCOP

Table 10-6. Summary of Emergency Generator and Fire Pump Engines (EU21 and 22) BACT Determinations

Pollutant	Emission Unit	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
		Value	Units		
NO_X	EU21 EU22	4.65 2.76	g/hp-hr[145] g/hp-hr[146]	• EPA certified engine	• EPA certified engine
CO	EU21 EU22	2.6	g/hp-hr	• EPA certified engine	• EPA certified engine
VOC	EU21 EU22	0.12 0.22	g /hp-hr[147] g hp-hr[148]	• EPA certified engine	• EPA certified engine
$PM/PM_{10}/PM_{2.5}$	EU21 EU22	0.15	g/hp-hr	• EPA certified engine	• EPA certified engine
CO_2e	EU21 EU22	163	lb/MMBtu	• Fuel selection • GCOP	• Use of permitted fuel and GCOP

[145] This proposed BACT limit is the NO_X fraction of the combined NO_X + NMHC BACT limit set equal to the applicable NSPS IIII standard.

[146] This proposed BACT limit is the NO_X fraction of the combined NO_X + NMHC BACT limit set equal to the applicable NSPS IIII standard.

[147] This proposed BACT limit is the VOC fraction of the combined NO_X + NMHC BACT limit set equal to the applicable NSPS IIII standard.

[148] This proposed BACT limit is the VOC fraction of the combined NO_X + NMHC BACT limit set equal to the applicable NSPS IIII standard.

Table 10-7. Summary of Other Source BACT Determinations

Pollutant	Emission Unit	BACT Emission Limit		BACT Control Type	Compliance Demonstration Method
		Value	Units		
$PM/PM_{10}/PM_{2.5}$	EU25	0.005	% drift loss	• Drift eliminators	• Use of drift eliminators
VOC	EU26A, EU26B, EU27, & EU28	N/A	N/A	• None	• Maintain tanks in good operating condition
CO_2e	EU30 & EU31	0.5	% leak rate, annual avg	• Leak detection system	• Leak detection system
$PM/PM_{10}/PM_{2.5}$	EU32	N/A	N/A	• BMP	• Records of measures to minimize emissions
VOC	EU33	0.42	tpy	• AVO inspections	• Weekly AVO inspections
CO_2e	EU33	919	tpy	• AVO inspections	• Weekly AVO inspections
H_2SO_4	EU34	N/A	N/A	• None	• Maintain tank in good operating condition

11. PROPOSED TITLE V PERMIT CHANGES

To accommodate the new emission unit installations and other changes encompassed by the Cooper Project, several changes will need to be made in the amended Title V permit for the facility. To assist in KDAQ's review and processing of the application and the development of an amended Draft Permit, this section of the application report highlights the key changes that will need to be considered. Additionally, EKPC has provided a suggested permit incorporating these changes in **Appendix F**.

11.1 Changes to Existing Unit Permit Terms and Conditions

The existing Title V permit includes several terms and conditions in Section B and Section D that require revision due to the Cooper Project. Section B includes detailed information for existing emission units, including unit descriptions, permitted fuels, maximum continuous ratings, and applicable federal and state regulatory requirements. Section D includes source emission limitations and testing requirements. **Table 11-1** provides a list of key permit changes needed within these sections to reflect the project covered by this permit action, along with an explanation for the basis of the changes.

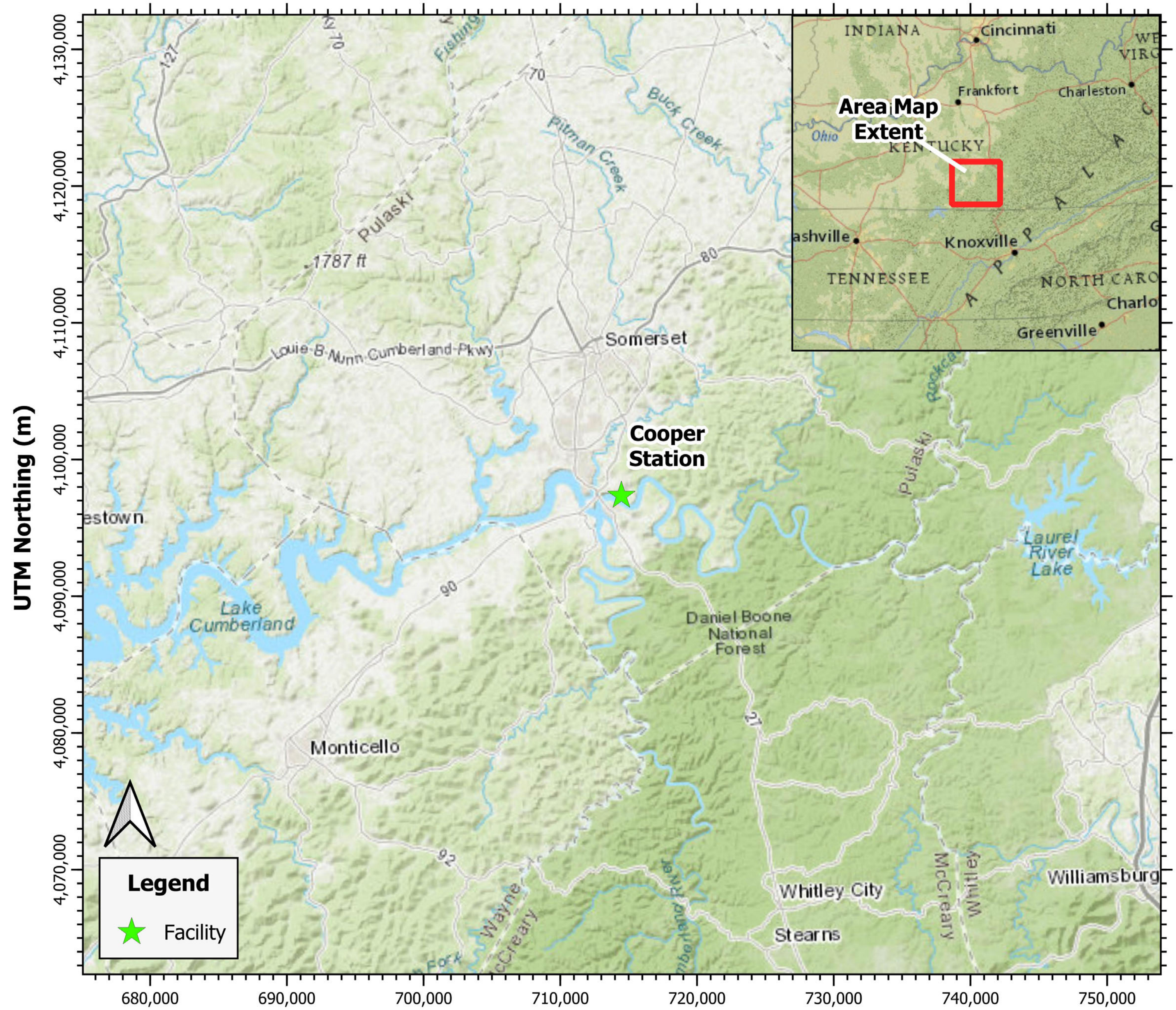
Table 11-1. Changes to Existing Unit Title V Permit Terms and Conditions

Permit Section	Emission Unit	Description of Changes Needed
Section B	EU02	• Update primary fuel to include the 100% NG and co-firing scenarios • Remove reference to wood waste combustion • Update maximum continuous rating to 2,433 MMBtu/hr • Add BACT operating and emission limits under 401 KAR 51:017 as described in application Sections 8 and 10 • Add compliance demonstration methods for BACT requirements as described in application Sections 8 and 10 • Add NO_X modeling-based emission limit for combined EU01 and EU02 stack under 401 KAR 51:017 Section 9 • Add control equipment operating conditions under 401 KAR 51:017 to specify control equipment requirements under the proposed 100% NG and co-firing scenarios
Section B	EU03, EU07	• Add modeling-based coal throughput limit of 463,566 tpy under 401 KAR 51:017 Section 9
Section D	EU02	• Add 12-month rolling SO_2 limit applicable to EU02 and new CTs to preclude applicability of 401 KAR 51:017 • Add compliance demonstration method for 12-month rolling SO_2 limit to preclude applicability of 401 KAR 51:017

11.2 Addition of New Permit Terms and Conditions

As discussed, the Cooper Project requires the inclusion of new emission units in the Title V permit. For each new unit, the suggested permit in **Appendix F** includes terms and conditions reflecting the SO_2 synthetic minor emission limit outlined in Section 4.7 of the application, applicable federal and state regulations detailed in Section 5 and DEP7007 Section V, BACT requirements and compliance demonstration methods from Sections 7, 9, and 10, and definitions of terms used in the permit. EKPC requests that KDAQ incorporate the suggested permit terms and conditions into the Title V permit to ensure the new emission units comply with all applicable regulatory requirements upon the Cooper Project's commercial operation date.

APPENDIX A. MAPS AND PROCESS FLOW DIAGRAMS



EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative

EKPC | Burnside, KY

Figure A-1. Area Map for Cooper Station in Burnside KY

All coordinates shown in
UTM Zone 16, NAD 83 Datum

Prepared By: Trinity Consultants

909 Wright's Summit Pkwy, Ste. 230
Project Number 241801.0040

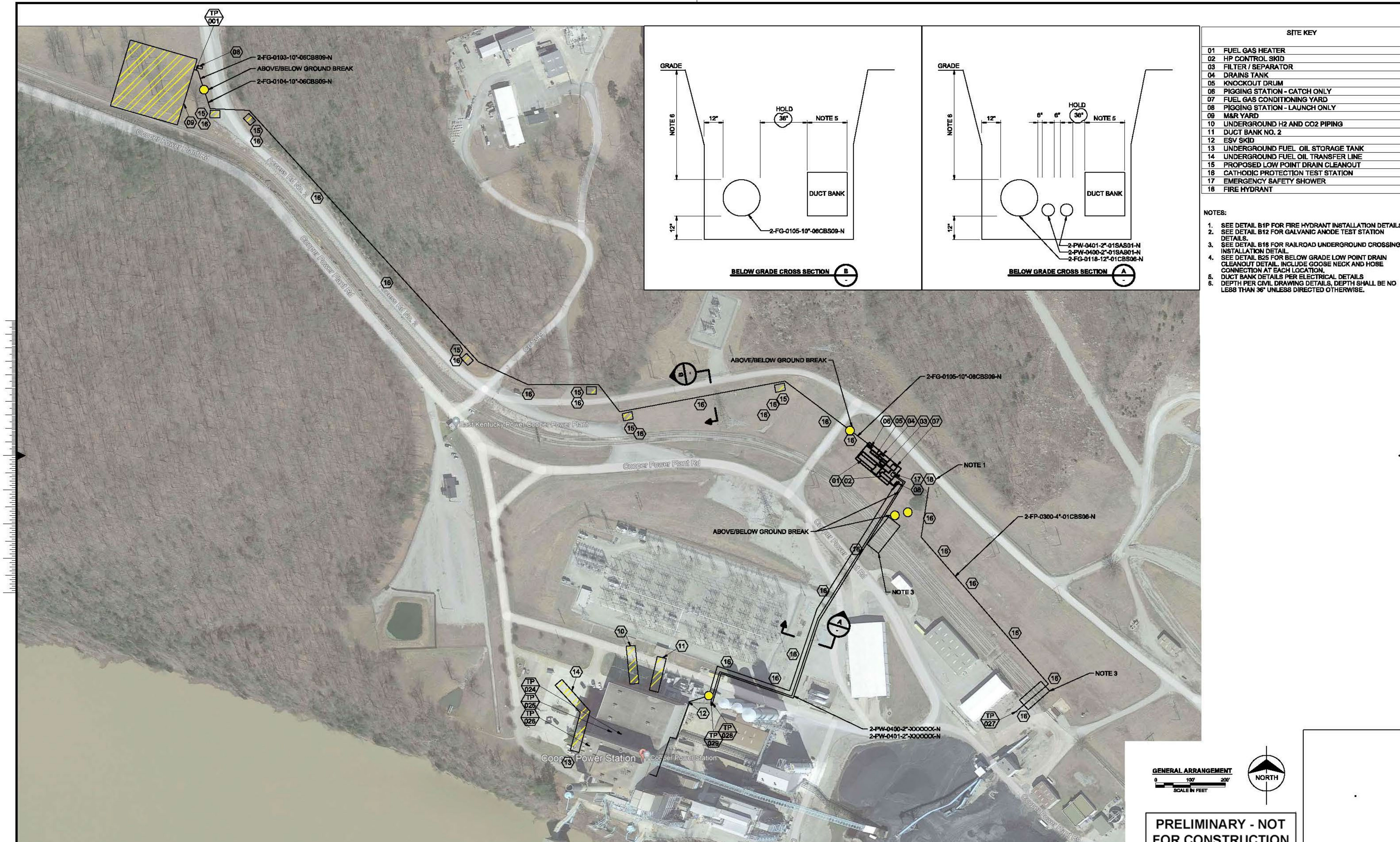
EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy Cooperative

EKPC | Burnside, KY

Figure A-2. Proposed Layout of New CCGT Operations

Prepared By: Trinity Consultants

909 Wright's Summit Pkwy, Ste. 230
Project Number 241801.0040



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EKPC | Burnside, KY

Figure A-3. Proposed Layout of New / Modified C2 Operations

Prepared By: Trinity Consultants
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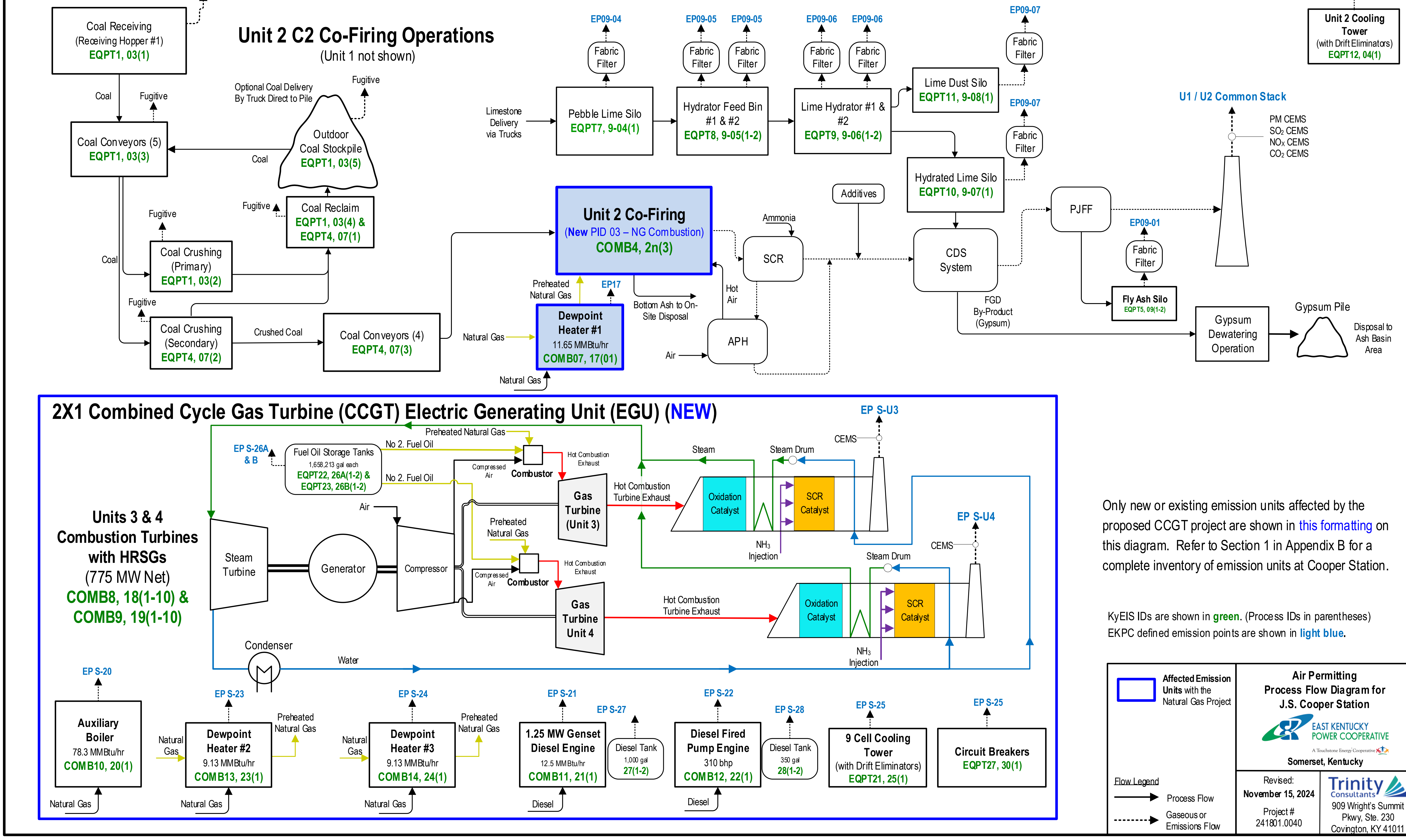
Project Number 241801.0040

Figure A-4 Air Permitting Process Flow Diagram

J.S. Cooper Station



APPENDIX B. EMISSIONS UNIT INDEX AND CALCULATIONS

1. EKPC Emission Unit Index

> The following table provides an index of existing emission units at EKPC along with new emission units being installed as part of the proposed Cooper Project. Existing Process IDs being shutdown are indicated by redline strikeout in red. Other than units being shutdown, there are no changes being made to other existing units at the plant as part of the Cooper Project.

> The emission unit ID nomenclature listed for the new emission units/process IDs to be installed as part of the CCGT EGU Project are shown in green font, and those to be installed/modified as part of the C2 Modification are shown in purple font. All new nomenclature are placeholders, to be finalized by KDAQ upon issuance of an amended Title V operating permit.

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
1	COMB001	1	01	Indirect Heat Exchanger #1	Indirect Heat Exchanger #1 Pulverized Coal-Fired, Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal ~~Secondary Fuel: Wood Waste (up to 3% by weight in blend)~~ Startup Fuel: Number Two Fuel Oil	Pulverized Coal	ESP, LNB, DFGD, PJFF				10100202	External Combustion Boilers - Electric Generation (1-01) - Bituminous/Subbituminous Coal (1-01-002) - Pulverized Coal: Dry Bottom (Bituminous Coal) (1-01-002-02)	Tons Bituminous Coal Burned	401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:240, 51:250, 51:260, ~~51:210, 51:220, 51:230,~~ 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63(Subpart UUUUU; MATS), 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree	2/9/1965	No	Yes	
~~1~~	~~COMB001~~	~~1~~	~~02~~	~~Indirect Heat Exchanger #1~~	~~Indirect Heat Exchanger #1 Pulverized Coal-Fired, Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Wood Waste (up to 3% by weight in blend) Startup Fuel: Number Two Fuel Oil Maximum Continuous Rating: 1,080 MMBtu/hr~~	~~Coal/Wood Waste Blend~~	~~ESP, LNB, DFGD, PJFF~~				~~10200902~~	~~External Combustion Boilers - Industrial (1-02) - Wood/Bark Waste (1-02-009) - Wood/Bark-fired Boiler (> 50,000 Lb Steam) (1-02-009-02)~~	~~Tons Wood/Bark Burned~~	~~401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:240, 51:250, 51:260, 51:210, 51:220, 51:230, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63(Subpart UUUUU; MATS), 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree~~	~~2/9/1965~~	~~No~~	~~Yes~~	Please remove
2n	COMB004	2n	01	Indirect Heat Exchanger #2	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas	Pulverized Coal	LNBs, DFGD, SCR, PJFF, FuelSolv Treatment	N/A	N/A	N/A	10100202	External Combustion Boilers - Electric Generation (1-01) - Bituminous/Subbituminous Coal (1-01-002) - Pulverized Coal: Dry Bottom (Bituminous Coal) (1-01-002-02)	Tons Bituminous Coal Burned	401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:240, 51:250, 51:260, ~~51:210, 51:220, 51:230,~~ 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63(Subpart UUUUU; MATS), 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree	10/28/1969	No	Yes	
~~2n~~	~~COMB004~~	~~2n~~	~~02~~	~~Indirect Heat Exchanger #2~~	~~Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas; Maximum Continuous Rating: 2,089 MMBtu/hr~~	~~Coal/Wood Waste Blend~~	~~LNBs, DFGD, SCR, PJFF, FuelSolv Treatment~~	~~N/A~~	~~N/A~~	~~N/A~~	~~10200902~~	~~External Combustion Boilers - Industrial (1-02) - Wood/Bark Waste (1-02-009) - Wood/Bark-fired Boiler (> 50,000 Lb Steam) (1-02-009-02)~~	~~Tons Wood/Bark Burned~~	~~401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:210, 51:220, 51:230, 51:240, 51:250, 51:260, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63 (Subpart UUUUU; MATS)~~	~~10/28/1969~~	~~No~~	~~Yes~~	Please remove
2n	COMB004	2n	03	Indirect Heat Exchanger #2	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas	Natural Gas	DFGD (Co-Firing Only), SCR, PJFF, GCP	N/A	N/A	N/A	10100601	External Combustion Boilers - Electric Generation (1-01) - Natural Gas (1-01-006) - Boilers > 100 Million Btu/hr except Tangential (1-01-006-01)	Million Cubic Feet Natural Gas Burned	401 KAR 61:015, 63:002 (MATS; Co-Firing Only), 51:017, 51:160, 52:060, 51:240, 51:250, 51:260, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63 (Subpart UUUUU; MATS for Coal & Co-Firing Only); 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree	2/1/2028	No	Yes	
3	EQPT0001	3	01		Coal Handling Operations	Receiving Hopper No. 1	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501008	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Unloading (3-05-010-08)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	
3	EQPT0001	3	02		Coal Handling Operations	Crusher (Primary)	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501010	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Crushing (3-05-010-10)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
3	EQPT0001	3	03		Coal Handling Operations	Convey & Transfer (5)	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501011	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Coal Transfer (3-05-010-11)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	
3	EQPT0001	3	04		Coal Handling Operations	Reclaim Hopper	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501011	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Coal Transfer (3-05-010-11)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	
3	EQPT0001	3	05		Coal Handling Operations	Stockpile	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501009	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Raw Coal Storage (3-05-010-09)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	
3	EQPT0001	3	06		Coal Handling Operations	Drop Pt into Bunkers	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30501011	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Coal Transfer (3-05-010-11)	Tons Coal Shipped	401 KAR 63:010	7/1/1969	Yes	Yes	
~~3~~	~~EQPT0001~~	~~3~~	~~07~~		~~Coal Handling Operations~~	~~Wood Waste Stockpile~~	~~DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~30700803~~	~~Industrial Processes - Pulp and Paper and Wood Products (3-07) - Sawmill Operations (3-07-008) - Sawdust Pile Handling (3-07-008-03)~~	~~Tons Sawdust Processed~~	~~401 KAR 63:010~~	~~7/1/1969~~	~~Yes~~	~~Yes~~	Please remove
~~3~~	~~EQPT0001~~	~~3~~	~~08~~		~~Coal Handling Operations~~	~~Wood Waste Storage~~	~~DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~30703002~~	~~Industrial Processes - Pulp and Paper and Wood Products (3-07) - Miscellaneous Wood Working Operations (3-07-030) - Wood Waste Storage Bin Loadout (3-07-030-02)~~	~~Tons Wood Waste Processed~~	~~401 KAR 63:010~~	~~7/1/1969~~	~~Yes~~	~~Yes~~	Please remove
3	EQPT0001	3	09		Coal Handling Operations	Unpaved Yard Area	DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010	7/1/1969	Yes	Yes	
4	EQPT0012	4	01		Unit 2 Cooling Tower	Cooling Tower	Drift Eliminators	N/A	N/A	N/A	38500101	Industrial Processes - Cooling Tower (3-85) - Process Cooling (3-85-001) - Mechanical Draft (3-85-001-01)	Million Gallons Cooling Water Throughput	401 KAR 59:010	1/1/2007	No	Yes	
5	EQPT0002	5	01		Fly Ash and Lime Waste Silo A and B #1	Pneumatic Convey to Silos	Fabric Filter Baghouse	N/A	N/A	N/A	39999999	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - See Comment ** (3-99-999-99)	Tons Material Processed	401 KAR 59:010; 40 CFR 64 CAM	11/29/1993	No	Yes	
7	EQPT0004	7	01		Coal Crushing Facility	Reclaim Hopper	N/A	N/A	N/A	N/A	30501010	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Crushing (3-05-010-10)	Tons Coal Shipped	40 CFR 60, Subpart Y	12/4/1998	Yes	Yes	
7	EQPT0004	7	02		Coal Crushing Facility	Crusher (Secondary)	N/A	N/A	N/A	N/A	30501010	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Crushing (3-05-010-10)	Tons Coal Shipped	40 CFR 60, Subpart Y	12/4/1998	Yes	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
7	EQPT0004	7	03		Coal Crushing Facility	Convey & Transfer (4)	N/A	N/A	N/A	N/A	30501010	Industrial Processes - Mineral Products (3-05) - Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010) - Crushing (3-05-010-10)	Tons Coal Shipped	40 CFR 60, Subpart Y	12/4/1998	Yes	Yes	
8	COMB006	8	01	Emergency Diesel Generator	Emergency Generator, CAT 3516	Diesel Firing	N/A	N/A	N/A	N/A	20100101	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Turbine (2-01-001-01)	1000 Gallons Distillate Oil (Diesel) Burned	40CFR63 Subpart ZZZZ	1/1/1998	No	Yes	
9-01	EQPT0005	9-01	01		Fly Ash and Waste Product Silo C: 108,000 ft^3 capacity	Fly Ash and Waste Silo #1	Fabric Filter	N/A	09-01	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-01	EQPT0005	9-01	02		Fly Ash and Waste Product Silo C: 108,000 ft^3 capacity	New Waste Product Silo #2	Fabric Filter	N/A	09-01	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-03	EQPT0006	9-03	01		Vacuum Systems #1 & #2	Vacuum System #1	Fabric Filter	N/A	09-03	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010; 40 CFR 64 CAM	12/31/2010	No	Yes	
9-03	EQPT0006	9-03	02		Vacuum Systems #1 & #2	Vacuum System #2	Fabric Filter	N/A	09-03	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010; 40 CFR 64 CAM	12/31/2010	No	Yes	
9-04	EQPT0007	9-04	01		Pebble Lime Silo	Pebble Lime Silo	Fabric Filter	N/A	09-04	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010; 40 CFR 64 CAM	12/31/2010	No	Yes	
9-05	EQPT0008	9-05	01		Pebble Lime Silo A & B	Hydrator Feed Bin #1	Fabric Filter	N/A	09-05	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-05	EQPT0008	9-05	02		Pebble Lime Silo A & B	Hydrator Feed Bin #2	Fabric Filter	N/A	09-05	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-06	EQPT0009	9-06	01		Lime Hydrator A & B	Lime Hydrator #1	Fabric Filter	N/A	09-06	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-06	EQPT0009	9-06	02		Lime Hydrator A & B	Lime Hydrator #2	Fabric Filter	N/A	09-06	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	
9-07	EQPT0010	9-07	01		Hydrated Lime Silo	Hydrated Lime Silo	Fabric Filter	N/A	09-07	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010; 40 CFR 64 CAM	12/31/2010	No	Yes	
9-08	EQPT0011	9-08	01		Lime Dust Silo	Lime Dust Silo	Fabric Filter	N/A	09-08	N/A	30510298	Industrial Processes - Mineral Products (3-05) - Bulk Materials Storage Bins (3-05-102) - Mineral: Specify in Comments (3-05-102-98)	Tons Material Processed	401 KAR 59:010	12/31/2010	No	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
10	AREA0002	10	01		Paved Roadways	Paved Haul Road	Dust Suppression	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010	7/1/1969	Yes	Yes	
10	AREA0002	10	02		Paved Roadways	New Haul Road	Dust Suppression	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010	7/1/1969	Yes	Yes	
12	EQPT0013	12	01	Communication Tower Emergency Generator	Olympian G35LG	Liquid Propane Gas (LPG) Usage	N/A				20301001	Internal Combustion Engines - Commercial/Institutional (2-03) - Liquified Petroleum Gas (LPG) (2-03-010) - Propane: Reciprocating (2-03-010-01)	1000 Gallons Liquified Petroleum Gas (LPG) Burned	40 CFR 60, Subpart JJJJ; 40 CFR 63, Subpart ZZZZ	3/25/2011	No	Yes	
13	EQPT0016	13	01	Fire Pump Engine	Scania F674DSJF	No 2 Fuel Oil Usage	N/A				20200102	Internal Combustion Engines - Industrial (2-02) - Distillate Oil (Diesel) (2-02-001) - Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned	40 CFR 63, Subpart ZZZZ	1/1/1978	No	Yes	
14	EQPT0017	14	01	Emergency Generator	Burnside Service Center; Ford LRG425	Liquid Propane Gas (LPG) Usage	N/A				20301001	Internal Combustion Engines - Commercial/Institutional (2-03) - Liquified Petroleum Gas (LPG) (2-03-010) - Propane: Reciprocating (2-03-010-01)	1000 Gallons Liquified Petroleum Gas (LPG) Burned	40 CFR 63, Subpart ZZZZ	1/1/2005	No	NO - EU REMOVED 2/2018	
16	EQPT0020	16	01	Leachate Transfer Pump Engine	Honda EM6500SX, Propane Fired	Propane	N/A				20201001	Internal Combustion Engines - Industrial (2-02) - Liquified Petroleum Gas (LPG) (2-02-010) - Propane: Reciprocating (2-02-010-01)	1000 Gallons Liquified Petroleum Gas (LPG) Burned	40 CFR 63, Subpart ZZZZ 40 CFR 60, Subpart JJJJ	7/15/2019	No	Yes	
17	**COMB0007**	**17**	**01**	**NG-Fired Dew Point Heater No. 1**	**NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)**	**Natural Gas Firing**	**N/A**	**N/A**	**S-17**	**N/A**	**39990003**	**Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)**	**Million Cubic Feet Natural Gas Burned**	**401 KAR 59:015, 401 KAR 60.005 (NSPS Dc)**	**2/1/2028**	**No**	**Yes**	
18	**COMB0008**	**18**	**01**	**Unit 3 Gas Turbine**	**NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST**	**Natural Gas Firing in CT**	**U3 CatOx & U3 SCR**	**U3-C1 & U3-C2**	**S-U3**	**Vertically Unobstructed Stack**	**20100201**	**Internal Combustion Engines - Electric Generation (2-01) - Natural Gas (2-01-002) - Turbine (2-01-002-01)**	**Million Cubic Feet Natural Gas Burned**	**401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)**	**1/1/2027**	**No**	**Yes**	
18	**COMB0008**	**18**	**02**	**Unit 3 Gas Turbine**	**NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST**	**No. 2 FO Firing in CT**	**U3 CatOx & U3 SCR**	**U3-C1 & U3-C2**	**S-U3**	**Vertically Unobstructed Stack**	**20100101**	**Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Turbine (2-01-001-01)**	**1000 Gallons Distillate Oil (Diesel) Burned**	**401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)**	**1/1/2027**	**No**	**Yes**	
18	**COMB0008**	**18**	**03**	**Unit 3 Gas Turbine**	**NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST**	**Cold Startup Events on Natural Gas**	**N/A**	**N/A**	**S-U3**	**Vertically Unobstructed Stack**	**39999993**	**Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)**	**Each Parts Processed**	**401 KAR 51:017**	**1/1/2027**	**No**	**Yes**	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
18	COMB0008	18	04	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Warm Startup Events on Natural Gas	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	05	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Hot Startup Events on Natural Gas	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	06	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Shutdown Events on Natural Gas	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	07	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Cold Startup Events on Fuel Oil	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	08	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Warm Startup Events on Fuel Oil	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	09	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Hot Startup Events on Fuel Oil	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
18	COMB0008	18	10	Unit 3 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST	Shutdown Events on Fuel Oil	N/A	N/A	S-U3	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	01	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Natural Gas Firing in CT	U4 CatOx & U4 SCR	U4-C1 & U4-C2	S-U4	Vertically Unobstructed Stack	20100201	Internal Combustion Engines - Electric Generation (2-01) - Natural Gas (2-01-002) - Turbine (2-01-002-01)	Million Cubic Feet Natural Gas Burned	401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)	1/1/2027	No	Yes	
19	COMB0009	19	02	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	No. 2 FO Firing in CT	U4 CatOx & U4 SCR	U4-C1 & U4-C2	S-U4	Vertically Unobstructed Stack	20100101	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Turbine (2-01-001-01)	1000 Gallons Distillate Oil (Diesel) Burned	401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)	1/1/2027	No	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
19	COMB0009	19	03	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Cold Startup Events on Natural Gas	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	04	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Warm Startup Events on Natural Gas	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	05	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Hot Startup Events on Natural Gas	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	06	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Shutdown Events on Natural Gas	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	07	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Cold Startup Events on Fuel Oil	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	08	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Warm Startup Events on Fuel Oil	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	09	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Hot Startup Events on Fuel Oil	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
19	COMB0009	19	10	Unit 4 Gas Turbine	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST	Shutdown Events on Fuel Oil	N/A	N/A	S-U4	Vertically Unobstructed Stack	39999993	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)	Each Parts Processed	401 KAR 51:017	1/1/2027	No	Yes	
20	COMB0010	20	01	NG-Fired Auxiliary Boiler	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)	Natural Gas Firing	N/A	N/A	S-20	TBD	10200602	External Combustion Boilers - Industrial (1-02) - Natural Gas (1-02-006) - 10-100 Million Btu/hr (1-02-006-02)	Million Cubic Feet Natural Gas Burned	401 KAR 51:017, 59:015, 60:005, & 63:002, 40 CFR 60 Subpart Dc, 40 CFR 63 Subpart DDDDD	1/1/2027	No	Yes	
21	COMB0011	21	01	1.25 MW Generator/Engine	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)	Diesel Firing	N/A	N/A	S-21	TBD	20100102	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)	1000 Gallons Distillate Oil (Diesel) Burned	NSPS IIII, RICE MACT, 401 KAR 51:017	1/1/2027	No	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
22	COMB0012	22	01	310 HP Diesel Pump/Engine	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp	Diesel Firing	N/A	N/A	S-22	TBD	20100102	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)	1000 Gallons Distillate Oil (Diesel) Burned	NSPS IIII, RICE MACT, 401 KAR 51:017	1/1/2027	No	Yes	
23	COMB0013	23	01	NG-Fired Dew Point Heater No. 2	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)	Natural Gas Firing	N/A	N/A	S-23	TBD	39990003	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)	Million Cubic Feet Natural Gas Burned	401 KAR 59:015, 401 KAR 51:017	1/1/2027	No	Yes	
24	COMB0014	24	01	NG-Fired Dew Point Heater No. 3	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)	Natural Gas Firing	N/A	N/A	S-24	TBD	39990003	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)	Million Cubic Feet Natural Gas Burned	401 KAR 59:015, 401 KAR 51:017	1/1/2027	No	Yes	
25	EQPT0021	25	01	CCGT Cooling Tower	One Mechanical Draft Cooling Tower, 9 Cells	Recirculating Water	Inherent drift eliminators	N/A	S-25	TBD	38500101	Industrial Processes - Cooling Tower (3-85) - Process Cooling (3-85-001) - Mechanical Draft (3-85-001-01)	Million Gallons Cooling Water Throughput	401 KAR 59:010, 401 KAR 51:017	1/1/2027	Yes	Yes	
26A	EQPT0022	26A	01	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	Breathing Losses	N/A	N/A	S-26A	TBD	42500301	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)	1000 Gallon-Years Liquid Storage Capacity	401 KAR 63:020; 401 KAR 51:017	1/1/2027	No	Yes	
26A	EQPT0022	26A	02	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	Working Losses	N/A	N/A	S-26A	TBD	42500302	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)	1000 Gallons Liquid Throughput	401 KAR 63:020; 401 KAR 51:017	1/1/2027	No	Yes	
26B	EQPT0023	26B	01	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	Breathing Losses	N/A	N/A	S-26B	TBD	42500301	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)	1000 Gallon-Years Liquid Storage Capacity	401 KAR 63:020; 401 KAR 51:017	1/1/2027	No	Yes	
26B	EQPT0023	26B	02	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	Working Losses	N/A	N/A	S-26B	TBD	42500302	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)	1000 Gallons Liquid Throughput	401 KAR 63:020; 401 KAR 51:017	1/1/2027	No	Yes	
27	EQPT0024	27	01	1,000 gallon Diesel Storage Tank	1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine	Breathing Losses	N/A	N/A	S-27	TBD	42500301	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)	1000 Gallon-Years Liquid Storage Capacity	401 KAR 51:017	1/1/2027	No	Yes	
27	EQPT0024	27	02	1,000 gallon Diesel Storage Tank	1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine	Working Losses	N/A	N/A	S-27	TBD	42500302	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)	1000 Gallons Liquid Throughput	401 KAR 51:017	1/1/2027	No	Yes	
28	EQPT0025	28	01	350 gallon Diesel Storage Tank	350 Gallon Diesel Storage Tank for Fire Pump Engine	Breathing Losses	N/A	N/A	S-28	TBD	42500301	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)	1000 Gallon-Years Liquid Storage Capacity	401 KAR 51:017	1/1/2027	No	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
28	EQPT0025	28	02	350 gallon Diesel Storage Tank	350 Gallon Diesel Storage Tank for Fire Pump Engine	Working Losses	N/A	N/A	S-28	TBD	42500302	Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)	1000 Gallons Liquid Throughput	401 KAR 51:017	1/1/2027	No	Yes	
29A	EQPT0026	29A	01	Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)	Natural Gas Firing	N/A	N/A	S-29A	TBD	39990003	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)	Million Cubic Feet Natural Gas Burned	401 KAR 59:015; 401 KAR 51:017	1/1/2027	No	Yes	
29B	EQPT0027	29B	01	Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)	14 Indirect-Fired HVAC Heaters (0.061 MMBtu/hr each)	Natural Gas Firing	N/A	N/A	S-29B	TBD	39990003	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)	Million Cubic Feet Natural Gas Burned	401 KAR 51:017	1/1/2027	No	Yes	
30	EQPT0028	30	01	Turbine Circuit Breakers	Three (3) Turbine Circuit Breakers with 30 lb. SF6 Circuits	SF6 Releases	N/A	N/A	S-30	TBD	20180001	Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)	Each-Year Facility Operating	401 KAR 51:017	1/1/2027	Yes	Yes	
31	EQPT0029	31	01	Switchyard/Station Circuit Breakers	Twelve (12) Switchyard/Station Circuit Breakers each with 58 lb. SF6 Circuits	SF6 Releases	N/A	N/A	S-31	TBD	20180001	Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)	Each-Year Facility Operating	401 KAR 51:017	1/1/2027	Yes	Yes	
32	AREA0003	32	01	CCGT Haul Roads	CCGT Haul Roads	19% Aqueous Ammonia Delivery	N/A	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010; 401 KAR 51:017	1/1/2027	Yes	Yes	
32	AREA0003	32	02	CCGT Haul Roads	CCGT Haul Roads	ULSFO Delivery	N/A	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010; 401 KAR 51:017	1/1/2027	Yes	Yes	
32	AREA0003	32	03	CCGT Haul Roads	CCGT Haul Roads	Water Treatment Building Chemicals Delivery	N/A	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010; 401 KAR 51:017	1/1/2027	Yes	Yes	
32	AREA0003	32	04	CCGT Haul Roads	CCGT Haul Roads	Cooling Tower Chemicals Delivery	N/A	N/A	N/A	N/A	30502011	Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)	Miles Vehicle Travelled	401 KAR 63:010; 401 KAR 51:017	1/1/2027	Yes	Yes	
33	EQPT0030	33	01	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives - GV Valves	N/A	N/A	N/A	N/A	30600811	Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Pipeline Valves: Gas Streams (3-06-008-11)	Each-Year Valve Operating	401 KAR 51:017	1/1/2027	Yes	Yes	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
33	EQPT0030	33	02	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives - Relief Valves	N/A	N/A	N/A	N/A	30600822	Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Vessel Relief Valves: All Streams (3-06-008-22)	Each-Year Valve Operating	401 KAR 51:017	1/1/2027	Yes	Yes	
33	EQPT0030	33	03	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives - Flanges	N/A	N/A	N/A	N/A	30600816	Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Flanges: All Streams (3-06-008-16)	Each-Year Flange Operating	401 KAR 51:017	1/1/2027	Yes	Yes	
33	EQPT0030	33	04	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives	Natural Gas Piping Fugitives - Sampling Connections	N/A	N/A	N/A	N/A	20180001	Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)	Each-Year Facility Operating	401 KAR 51:017	1/1/2027	Yes	Yes	
IA - 01		IA - 01			Storage vessels containing petroleum or organic liquids with a capacity of less than 10,567 gallons, providing (a) the vapor pressure of the stored liquid is less than 1.5 psia at storage temperature, or (b) vessels greater than 580 gallons with stored liquids having greater than 1.5 psia vapor pressure are equipped with a permanent submerged fill pipe									N/A				
IA - 02		IA - 02			Storage vessels containing inorganic aqueous liquids, except inorganic acids with boiling points below the maximum storage temperature at atmospheric pressure.									N/A				
IA - 03		IA - 03			#2 oil-fired space heaters or ovens rated at less than two million BTU per hour actual heat input, provided the maximum sulfur content is less than 0.5% by weight.									N/A				
IA - 04		IA - 04			Machining of metals, providing total solvent usage at the source for this activity does not exceed 60 gallons per month.									N/A				
IA - 05		IA - 05			Volatile organic compound and hazardous air pollutant storage containers, as follows: (a) Tanks, less than 1,000 gallons, and throughput less than 12,000 gallons per year; (b) Lubricating oils, hydraulic oils, machining oils, and machining fluids									N/A				
IA - 06		IA - 06			Machining where an aqueous cutting coolant continuously floods machining interface.									N/A				
IA - 07		IA - 07			Degreasing operations, using less than 145 gallons per year.									N/A				
IA - 08		IA - 08			Maintenance equipment, not emitting HAPs: brazing, cutting torches, soldering, welding.									N/A				
IA - 09		IA - 09			Underground conveyors.									401 KAR 63:010				
IA - 10		IA - 10			Coal bunker and coal scale exhausts.									401 KAR 63:010				
IA - 11		IA - 11			Blowdown (sight glass, boiler, compressor, pump, cooling tower).									N/A				
IA - 12		IA - 12			On-site fire and emergency response training.									N/A				

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emissions Unit Name	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Stack Description	SCC Code	SCC Description	SCC Units	Applicable Regulations	Construction Date	Fugitive Emissions?	Count Emissions for PTE?	Project Impacts
IA - 13		IA - 13			Grinding and machining operations vented through fabric filters, scrubbers, mist eliminators, or electrostatic precipitators (e.g., deburring, buffing, polishing, abrasive blasting, pneumatic conveying, woodworking).									401 KAR 63:010				
IA - 14		IA - 14			Vents from ash transport systems not operated at positive pressure.									N/A				
IA - 15		IA - 15			Wastewater treatment (for stream less than 1% oil and grease).									N/A				
IA - 16		IA - 16			Sanitary sewage treatment.									N/A				
IA - 17		IA - 17			Heat exchanger cleaning and repair.									N/A				
IA - 18		IA - 18			Equipment used exclusively for forging, pressing, drawing, stamping, spinning, or extruding metals. This does not include emissions due to quenching activities.									N/A				
IA - 19		IA - 19			Repair and maintenance of ESP, fabric filters, etc.									N/A				
IA - 20		IA - 20			Ash handling, ash pond and ash pond maintenance									401 KAR 63:010				
IA - 21		IA - 21			Laboratory fume hoods and vents used exclusively for chemical or physical analysis, or for "bench scale production" R&D facilities									N/A				
IA - 22		IA - 22			Covered conveyors for coal or coke that convey less than 200 tons per day									401 KAR 63:010				
IA - 23		IA - 23			EU 05 & 09 - Fly ash loadout systems (Silos A, B & C) configured for either railcar or truck									401 KAR 63:010				
IA - 24		IA - 24			Wood Unloading Area (600 tph)									401 KAR 63:010				
IA - 25		IA - 25			Portable Backup Conveyer									401 KAR 63:010				
IA - 26		IA - 26			DusTreat CF9156 in 850 gallon tank									401 KAR 63:010				
IA - 27		IA - 27			DusTreat DC6109 in 300 gallon tote									401 KAR 63:010				
IA - 28		IA - 28			Powdered Activated Carbon (PAC) System (500 lb./hr. max)									401 KAR 59:010				
IA - 29		**IA - 29**	**01**		**19% aqueous ammonia tank(s)**									**N/A**				
34	**EQPT0031**	**34**	**01**	**93% Sulfuric Acid Tank**	**93% Sulfuric Acid Tank**	**Breathing Losses**	**N/A**	**N/A**	**IA-30**	**TBD**	**42500301**	**Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)**	**1000 Gallon-Years Liquid Storage Capacity**	**401 KAR 51:017**	**1/1/2027**	**No**	**Yes**	
34	**EQPT0031**	**34**	**02**	**93% Sulfuric Acid Tank**	**93% Sulfuric Acid Tank**	**Working Losses**	**N/A**	**N/A**	**IA-30**	**TBD**	**42500302**	**Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)**	**1000 Gallons Liquid Throughput**	**401 KAR 51:017**	**1/1/2027**	**No**	**Yes**	

2. Cooper Project Emissions Summary Table

> The table below tallies the net emission increases associated with the proposed Cooper Project for all relevant regulated NSR pollutants and compares them to the PSD Significant Emission Rate thresholds. Values shown for new emission units are their potential emissions, taking into account inherent and proposed operating limitations and control device configurations. Values shown for the modified emission units include the projected emissions increase calculated in accordance with 401 KAR 51:017, Section 1(4)(a).

KyEIS Equip ID	KyEIS Source ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e* (tpy)
New Emission Units												
CCGT EGU Project												
COMB0008	18	Unit 3 Gas Turbine	82.35	82.35	82.35	165	2,390	226	16.24	24.86	2.00E-02	1,437,622
COMB0009	19	Unit 4 Gas Turbine	82.35	82.35	82.35	165	2,390	226	16.24	24.86	2.00E-02	1,437,622
COMB0010	20	NG-Fired Auxiliary Boiler	0.615	1.12	1.12	3.75	1.01	1.78	0.462	3.54E-02	1.62E-04	38,881
COMB0011	21	1.25 MW Generator/Engine	0.181	0.181	0.181	5.64	3.16	0.151	5.87E-03			638
COMB0012	22	310 HP Diesel Pump/Engine	2.56E-02	2.56E-02	2.56E-02	0.471	0.444	3.82E-02	8.27E-04			89.92
COMB0013	23	NG-Fired Dew Point Heater No. 2	7.17E-02	0.131	0.131	1.89	3.17	0.207	5.38E-02	4.12E-03	1.89E-05	4,532
COMB0014	24	NG-Fired Dew Point Heater No. 3	7.17E-02	0.131	0.131	1.89	3.17	0.207	5.38E-02	4.12E-03	1.89E-05	4,532
EQPT0021	25	CCGT Cooling Tower	4.54	0.586	5.48E-03							
EQPT0022	26A	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs						0.410				
EQPT0023	26B	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs						0.410				
EQPT0024	27	1,000 gallon Diesel Storage Tank						5.22E-04				
EQPT0025	28	350 gallon Diesel Storage Tank						1.21E-04				
EQPT0026	29A	Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)	0.302	0.552	0.552	15.91	13.36	0.875	0.227	1.74E-02	7.95E-05	19,113
EQPT0027	29B	Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)	6.70E-03	1.22E-02	1.22E-02	0.353	0.296	1.94E-02	5.04E-03	3.85E-04	1.76E-06	424
EQPT0028	30	Turbine Circuit Breakers										5.29
EQPT0029	31	Switchyard/Station Circuit Breakers										40.89
EQPT0031	34	93% Sulfuric Acid Tank								1.46E-07		
Cooper 2 Co-Firing Project												
COMB0007	17	NG-Fired Dew Point Heater No. 1	9.51E-02	0.174	0.174	2.50	4.20	0.275	7.14E-02	5.47E-03	2.50E-05	6,011
Both Projects												
AREA0003	32	CCGT Haul Roads	0.770	0.154	3.78E-02							
EQPT0030	33	Natural Gas Piping Fugitives						0.424				919
Modified Existing Emission Unit Projected Emission Increases												
COMB004	2n	C2 Emissions Increase (PAE - BAE)	11.00	14.90	14.68	758	1,238	52.64	5.65	10.11	2.47E-03	816,284
Unmodified Existing Emission Unit Projected Emission Increases												
Various	3, 7, 10	Coal Handling (PAE - BAE)	2.64E-03	8.76E-04	1.21E-04							
Emissions Increase Summary												
Step 1 Project Emission Increases			**182**	**183**	**182**	**1,119**	**6,048**	**510**	**39.00**	**59.89**	**4.28E-02**	**3,766,715**
PSD/NSR Major Modification Threshold			25	15	10	40	100	40	40	7	0.6	75,000
Trigger PSD/NSR?			**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**

* CO_2e (GHG Pollutants) only become subject to regulation and potentially applicable to PSD if another regulated NSR pollutant triggers PSD.

3. Potential Emissions Summary for New CCGT Project Emission Units and Cooper 2 Modification

> The table below tallies the potential to emit for all new emission units associated with the proposed Cooper Project for all relevant regulated air pollutants.

KyEIS Equip ID	KyEIS Source ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e (tpy)
New Emission Units												
CCGT EGU Project												
COMB0008	18	Unit 3 Gas Turbine	82.35	82.35	82.35	165	2,390	226	16.24	24.86	2.00E-02	1,437,622
COMB0009	19	Unit 4 Gas Turbine	82.35	82.35	82.35	165	2,390	226	16.24	24.86	2.00E-02	1,437,622
COMB0010	20	NG-Fired Auxiliary Boiler	1.12	1.12	1.12	3.75	1.01	1.78	0.462	3.54E-02	1.62E-04	38,881
COMB0011	21	1.25 MW Generator/Engine	0.181	0.181	0.181	5.64	3.16	0.151	5.87E-03			638
COMB0012	22	310 HP Diesel Pump/Engine	2.56E-02	2.56E-02	2.56E-02	0.471	0.444	3.82E-02	8.27E-04			89.92
COMB0013	23	NG-Fired Dew Point Heater No. 2	0.131	0.131	0.131	1.89	3.17	0.207	5.38E-02	4.12E-03	1.89E-05	4,532
COMB0014	24	NG-Fired Dew Point Heater No. 3	0.131	0.131	0.131	1.89	3.17	0.207	5.38E-02	4.12E-03	1.89E-05	4,532
EQPT0021	25	CCGT Cooling Tower	4.54	0.586	5.48E-03							
EQPT0022	26A	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs						0.410				
EQPT0023	26B	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs						0.410				
EQPT0024	27	1,000 gallon Diesel Storage Tank						5.22E-04				
EQPT0025	28	350 gallon Diesel Storage Tank						1.21E-04				
EQPT0026	29A	Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)	0.552	0.552	0.552	15.91	13.36	0.875	0.227	1.74E-02	7.95E-05	19,113
EQPT0027	29B	Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)	1.22E-02	1.22E-02	1.22E-02	0.353	0.296	1.94E-02	5.04E-03	3.85E-04	1.76E-06	424
EQPT0028	30	Turbine Circuit Breakers										5.29
EQPT0029	31	Switchyard/Station Circuit Breakers										40.89
EQPT0031	34	93% Sulfuric Acid Tank								1.46E-07		
Cooper 2 Co-Firing Project												
COMB0007	17	NG-Fired Dew Point Heater No. 1	0.174	0.174	0.174	2.50	4.20	0.275	7.14E-02	5.47E-03	2.50E-05	6,011
Both Projects												
AREA0003	32	CCGT Haul Roads	0.770	0.154	3.78E-02							
EQPT0030	33	Natural Gas Piping Fugitives						0.424				919
Subtotal			**172**	**168**	**167**	**362**	**4,809**	**457**	**33.35**	**49.78**	**4.04E-02**	**2,950,431**

EAST KENTUCKY POWER COOPERATIVE

Trinity Consultants

Emission Unit ID	KyEIS Source ID	Description	NH_3 (tpy)	Acetalde-hyde (tpy)	Formalde-hyde (tpy)	Ethylbenzene (tpy)	Toluene (tpy)	Xylenes (tpy)	Nickel (tpy)	Mercury (tpy)	Hexane (tpy)	Manganese (tpy)	Total HAP (tpy)
New Emission Units													
CCGT EGU Project													
COMB0008	18	Unit 3 Gas Turbine	80.73	1.78	2.54	0.226	0.919	0.453	6.58E-03	1.72E-03		1.13	7.60
COMB0009	19	Unit 4 Gas Turbine	80.73	1.78	2.54	0.226	0.919	0.453	6.58E-03	1.72E-03		1.13	7.60
COMB0010	20	NG-Fired Auxiliary Boiler			2.43E-02		1.10E-03		6.80E-04	8.41E-05	0.583	1.23E-04	0.611
COMB0011	21	1.25 MW Generator/Engine		9.76E-05	3.06E-04		1.09E-03	7.48E-04					6.60E-03
COMB0012	22	310 HP Diesel Pump/Engine		4.19E-04	6.44E-04		2.23E-04	1.56E-04					2.16E-03
COMB0013	23	NG-Fired Dew Point Heater No. 2			2.83E-03		1.28E-04		7.92E-05	9.81E-06	6.79E-02	1.43E-05	7.12E-02
COMB0014	24	NG-Fired Dew Point Heater No. 3			2.83E-03		1.28E-04		7.92E-05	9.81E-06	6.79E-02	1.43E-05	7.12E-02
EQPT0021	25	CCGT Cooling Tower											
EQPT0022	26A	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs											
EQPT0023	26B	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs											
EQPT0024	27	1,000 gallon Diesel Storage Tank											
EQPT0025	28	350 gallon Diesel Storage Tank											
EQPT0026	29A	Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)			1.19E-02		5.41E-04		3.34E-04	4.14E-05	0.286	6.05E-05	0.300
EQPT0027	29B	Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)			2.65E-04		1.20E-05		7.41E-06	9.17E-07	6.35E-03	1.34E-06	6.66E-03
EQPT0028	30	Turbine Circuit Breakers											
EQPT0029	31	Switchyard/Station Circuit Breakers											
EQPT0031	34	93% Sulfuric Acid Tank											
Cooper 2 Co-Firing Project													
COMB0007	17	NG-Fired Dew Point Heater No. 1			3.75E-03		1.70E-04		1.05E-04	1.30E-05	9.01E-02	1.90E-05	9.45E-02
Both Projects													
AREA0003	32	CCGT Haul Roads											
EQPT0030	33	Natural Gas Piping Fugitives											
Subtotal			**161**	**3.56**	**5.12**	**0.453**	**1.84**	**0.906**	**1.45E-02**	**3.59E-03**	**1.10**	**2.26**	**16.36**

4. Derivation of Emissions Factors and Calculations for EU 18: Unit 3 Gas Turbine

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 18: Unit 3 Gas Turbine are documented in this section. Note that the detailed emissions calculations in this section are representative of both CTs to be installed as part of the Cooper Project.

Emission Unit ID: 18
Emission Unit Name: Unit 3 Gas Turbine
Emission Unit Description: NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST
Equipment ID (SI): COMB0008

4.1 Process Unit(s)

> The new emission unit identification and associated process IDs proposed to be assigned within the Kentucky Emissions Inventory System (KyEIS) for the CT are shown below. The CT can fire natural gas (Process ID 1) and fuel oil (Process ID 2). Duct firing is not part of the design. Process IDs 3 through 10 encompass possible startup and shutdown operating events, consistent with conventional approaches for representing emissions from combustion turbines.

Process ID: 01
EU ID - PID: 18-01
Process Description: Natural Gas Firing in CT
Control Device ID: U3-C1 & U3-C2
Control Device Description: U3 CatOx & U3 SCR
Stack ID: S-U3
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: 401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)

Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code

SCC: 20100201
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Natural Gas (2-01-002) - Turbine (2-01-002-01)
SCC Units: Million Cubic Feet Natural Gas Burned

Process ID:	**02**
EU ID - PID:	**18-02**
Process Description:	**No. 2 FO Firing in CT**
Control Device ID:	U3-C1 & U3-C2
Control Device Description:	U3 CatOx & U3 SCR
Stack ID:	S-U3
Stack Description:	Vertically Unobstructed Stack
Applicable Regulation:	401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	20100101
SCC Description:	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Turbine (2-01-001-01)
SCC Units:	1000 Gallons Distillate Oil (Diesel) Burned

Process ID:	**03**	**04**	**05**	**06**
EU ID - PID:	**18-03**	**18-04**	**18-05**	**18-06**
Process Description:	**Cold Startup Events on Natural Gas**	**Warm Startup Events on Natural Gas**	**Hot Startup Events on Natural Gas**	**Shutdown Events on Natural Gas**
Control Device ID:	N/A	N/A	N/A	N/A
Control Device Description:	N/A	N/A	N/A	N/A
Stack ID:	S-U3	S-U3	S-U3	S-U3
Stack Description:	Vertically Unobstructed Stack	Vertically Unobstructed Stack	Vertically Unobstructed Stack	Vertically Unobstructed Stack
Applicable Regulation:	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017
Construction Date:	1/1/2027	1/1/2027	1/1/2027	1/1/2027
Fugitive Emissions?	No	No	No	No
Count Emissions for PTE?	Yes	Yes	Yes	Yes

Source Classification Code

SCC:	39999993	39999993	39999993	39999993

SCC Description: Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)

SCC Units: Each Parts Processed

Process ID:	07	08	09	10
EU ID - PID:	18-07	18-08	18-09	18-10
Process Description:	Cold Startup Events on Fuel Oil	Warm Startup Events on Fuel Oil	Hot Startup Events on Fuel Oil	Shutdown Events on Fuel Oil
Control Device ID:	N/A	N/A	N/A	N/A
Control Device Description:	N/A	N/A	N/A	N/A
Stack ID:	S-U3	S-U3	S-U3	S-U3
Stack Description:	Vertically Unobstructed Stack	Vertically Unobstructed Stack	Vertically Unobstructed Stack	Vertically Unobstructed Stack
Applicable Regulation:	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017
Construction Date:	1/1/2027	1/1/2027	1/1/2027	1/1/2027
Fugitive Emissions?	No	No	No	No
Count Emissions for PTE?	Yes	Yes	Yes	Yes
Source Classification Code				
SCC:	39999993	39999993	39999993	39999993
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)			
SCC Units:	Each Parts Processed			

4.2 Capacity and Fuel Information for 18-01 and 18-02

> The following provides the capacity information for the CCGT, as well as other relevant information used in the emissions estimates.

Natural Gas Higher Heating Value (HHV)	1,060	Btu/scf	Average for EKPC Inlet Gas
Natural Gas HHV per AP-42 Sections 1.4 & 3-1	1,020	Btu/scf	Default HHV
Natural Gas HHV per 40 CFR 98, Subpart C	1,026	Btu/scf	Default HHV
Maximum operating hours/yr	8,760	hr/yr	
Maximum operating hours/yr in SS if FO is combusted	7,680	hr NG/yr	= 8760 hr/yr - 1080 hr/yr for FO
Maximum operating hours/yr in SS during SUSD events	4,191	hr NG/yr	= [(9.50 hr/NG 24-hr event – 0.417 hr initial SD prior to CS) + (4.83 hr/NG WS Day x 6 WS Days) + (20.75 hr/NG HS Day x 12 HS Days)] x 15 cycles
Maximum Heat Input Capacity from NG Combustion Used for Emission Calculations	2,734	MMBtu/hr	Maximum CT Heat Input (HHV basis) from specs for NG firing (Siemens Case 5)
Maximum NG Consumption	2.579	MMscf/hr	= 2,734 MMBtu/hr / 1,060 Btu/scf
FO Higher Heating Value (HHV)	136.20	MMBtu/Mgal	Average for EKPC Fuel Oil
FO HHV per AP-42 Section 3-1	139.00	MMBtu/Mgal	Default HHV
FO HHV per 40 CFR 98, Subpart C	138.00	MMBtu/Mgal	Default HHV
Duration of FO Firing per Event	72	hr FO/event	Assumes worst-case of 3 straight days of FO operation
Total FO Tank Refilling Time	21	days refilling/event	Assumes average refilling time of 3 weeks
Total Days per FO Event	24	days/event	= 72 hr FO/event + 21 days refilling/event
Annual FO Events	15	events/yr	= 365 days/yr / 24 days/event
Maximum Possible Hours of FO Combustion	1,080	hr FO/yr	= 72 hr FO/event * 15.00 events/yr
Maximum operating hours/yr accounting for SUSD events	861.3	hr FO/yr	= (19.17 hr/FO 24-hr event + 48 hr – 0.5 hr SD prior to WS – 8 hr idling – 1.25 hr WS) x 15 cycles

Maximum Heat Input Capacity from FO Combustion Used for Emission Calculations	2,597	MMBtu/hr	Maximum CT Heat Input (HHV basis) from specs for FO firing (Siemens Case 203)
Maximum FO Consumption	19.065	Mgal/hr	= 2,597 MMBtu/hr / 136.20 MMBtu/Mgal

4.3 Derivation and Documentation of Steady-State Operation Emission Factors for 18-01

4.3.1 NSR-Regulated Pollutants

> Controlled emission factors (EFs) for all NSR-regulated pollutants have been calculated based on the worst-case hourly emissions profile from vendor specifications. Lead emissions are discussed in the HAP subsection below.

NO_X

Concentration in stack exhaust after SCR	2.0	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Rate	19.82	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)
Controlled Emission Factor	7.686	lb/MMscf	= 19.82 lb/hr / 2.579 MMscf/hr
Control Efficiency (**<u>not guaranteed</u>**)	86.67	%	Minimum control offered by vendor specs NG firing cases only
Uncontrolled Emission Factor	57.642	lb/MMscf	= 7.686 Controlled Emission Factor / (100% - 86.67%)

CO

Concentration in stack exhaust after oxidation catalyst	2.0	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Rate	12.07	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)
Controlled Emission Factor	4.679	lb/MMscf	= 12.07 lb/hr / 2.579 MMscf/hr
Control Efficiency (**<u>not guaranteed</u>**)	50.00	%	Minimum control offered by Vendor specs NG firing cases only
Uncontrolled Emission Factor	9.359	lb/MMscf	= 4.679 Controlled Emission Factor / (100% - 50.00%)

VOC

Concentration in Stack Exhaust	1.0	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Factor	1.340	lb/MMscf	= 3.46 lb/hr / 2.579 MMscf/hr
Controlled Emission Rate	3.46	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)
Control Efficiency (**<u>not guaranteed</u>**)	30	%	Conservative Estimate
Uncontrolled Emission Factor	1.914	lb/MMscf	= 3.457 Controlled Emission Rate / 2.579 Maximum NG Consumption / (100% - 30.00%)

SO_2

> The following estimate is based solely on a maximum sulfur input of 0.5 gr/Cscf and 100% conversion from S to SO_2 . In reality, the SO_2 should be reduced by the amount of SO_2 converted to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the following methodology does not account for these further reductions and thus the emission estimates are conservative.

Max Sulfur Content for Pipeline Gas	0.50	gr/Cscf	
Molecular Weight of S	32.07	lb/lbmol	
Molecular Weight of SO_2	64.07	lb/lbmol	
Uncontrolled Emission Rate	3.67	lb/hr	= 0.5 gr/Cscf * 10,000 Cscf/MMscf / 7,000 gr/lb / 1,060 * 2,734 MMBtu/hr * 64.07 lb /lbmole SO2 / 32.07 lb/lbmole S * 1 lbmole SO2/1 lbmole S * 100%
Uncontrolled Emission Factor	1.424	lb/MMscf	= 3.67 lb/hr / 2.579 MMscf/hr
Uncontrolled Emission Factor	1.34E-03	lb/MMBtu	= 3.67 lb/hr / 2,734 MMBtu/hr

H_2SO_4

> Within the combustion process, SO_2 can be further oxidized into SO_3, which then can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. 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, acid dew point, etc.

Uncontrolled Emission Rate of H_2SO_4	5.63	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)
Uncontrolled Emission Factor of H_2SO_4	2.181	lb/MMscf	= 5.63 lb/hr / 2.579 MMscf/hr
	2.06E-03	lb/MMBtu	= 5.63 lb/hr / 2,734 MMBtu/hr

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from the CTs. When EKPC asked each vendor to provide PM estimates, all vendors provided overly conservative estimates of PM (not guarantees). Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is a possibility under certain conditions. One pathway is the sulfate formation from H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$, as well as the nitrate formation in the form of NH_4NO_3. However, the PM emissions from these pathways are still expected to be low. Regardless, given uncertainties, EKPC conservatively used the information provided by the vendors for defining PM emissions. In all cases, all PM can be assumed to be less than 2.5 μm in mean diameter (i.e., PM = PM_0 = $PM_{2.5}$).

Uncontrolled Emission Rate	17.21	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)
Uncontrolled Emission Factor	6.672	lb/MMscf	= 17.21 lb/hr / 2.579 MMscf/hr
Uncontrolled Emission Factor	6.29E-03	lb/MMBtu	= 17.21 lb/hr / 2,734 MMBtu/hr

Greenhouse Gases

> Emission factors for GHGs are based on Subpart C of EPA's Greenhouse Gas Reporting Program (GHGRP, 40 CFR 98 Subpart C Table C-1 and Table C-2).
> The global warming multiplying factors for CH4 and N2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO2e emissions.

CO_2

Uncontrolled Emission Factor	116.98	lb/MMBtu	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	120,019	lb/MMscf	= 116.98 lb/MMBtu * 1,026 MMBtu/MMscf per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	309,584	lb/hr	= 120,019 lb/MMscf x 2.579 MMscf/hr

CH_4

Uncontrolled Emission Factor	0.0243	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.1 x 10^{-2} kg/MMBtu to lb/MMBtu
	24.88	lb/MMscf	= 0.0243 lb/MMBtu x 1,026 MMBtu/MMscf per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	64.2	lb/hr	= 24.881 lb/MMscf x 2.579 MMscf/hr

N_2O

Uncontrolled Emission Factor	0.0035	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.6 x 10^{-3} kg/MMBtu to lb/MMBtu
	3.62	lb/MMscf	= 0.0035 lb/MMBtu x 1,026 MMBtu/MMscf per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	9.34	lb/hr	= 3.619 lb/MMscf x 2.579 MMscf/hr

CO_2e

Global Warming Potentials of GHGs per amendment to 40 CFR 98, Subpart A (89 FR 31894, published April 25, 2024)

CO_2	1		
CH_4	28		89 FR 42218, May 14, 2024
N_2O	265		89 FR 42218, May 14, 2024
Uncontrolled Emission Factor	121,674	lb/MMscf	= (CO2 EF x CO2 GWP) + (CH4 EF x CH4 GWP) + (N2O EF x N2O GWP)
Uncontrolled Emission Rate	313,855	lb/hr	

4.3.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	5	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Uncontrolled Emission Factor	7.113	lb/MMscf	= 18.35 lb/hr x 2.579 MMscf/hr
Uncontrolled Emission Rate	18.35	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 5)

4.3.3 Hazardous Air Pollutants for CT

Formaldehyde

Concentration in stack exhaust	0.091	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement per 40 CFR §63.6100 and Table 1 of NESHAP YYYY
Molecular weight of HCHO	30.031	lb/lbmol	
Oxygen based F-Factor	8,710	dscf/MMBtu	RM Method 19 determination of Fd factor for natural gas combustion can use a default value of 8,710, or use equations 19-13 through 19.15. EKPC chose to use the default Fd factor from RM Method 19.
Controlled Emission Rate	0.60	lb/hr	= 1.0 atm STD x 30.031 lb/lbmol HCHO / 0.7302 ft3-atm/lbmol-°R / 527.67°R STD x 0.091 ppmvd @ 15% O2 /1E6 x 8,710.0 dscf/MMBtu x [(20.9% O2 / (20.9% O2 -15% O2)] x 2,734 MMBtu/hr
Controlled Emission Factor	0.232	lb/MMscf	= 0.60 lb/hr / 2.579 MMscf/hr

> Other than for formaldehyde (described above), emission factors for organic and metallic HAP emissions from natural gas-fired turbines published in AP-42, Section 3.1 are used to estimate potential emissions.

Pollutant	CAS No.	GT Uncontrolled EF (lb/MMBtu)	GT Uncontrolled EF (lb/MMscf)	Oxidation Catalyst Control Efficiency[4] (%)	GT After Oxidation Catalyst EF (lb/MMBtu)	GT After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
1,3-Butadiene	106-99-0	4.30E-07	4.39E-04	30%	3.01E-07	3.07E-04	AP-42 Table 3.1	2
Acetaldehyde	75-07-0	2.51E-04	2.56E-01	30%	1.76E-04	1.80E-01	AP-42 Table 3.1 & 3-4 of BID	1, 2
Acrolein	107-02-8	6.40E-06	6.53E-03	43%	3.62E-06	3.69E-03	AP-42 Table 3.1 & 3-4 of BID	1
Benzene	71-43-2	1.20E-05	1.22E-02	73%	3.26E-06	3.33E-03	AP-42 Table 3.1 & 3-4 of BID	1
Ethylbenzene	100-41-4	3.20E-05	3.26E-02	30%	2.24E-05	2.28E-02	AP-42 Table 3.1	2
Formaldehyde	50-00-0	7.10E-04	7.24E-01	68%	2.27E-04	2.32E-01	EKPC Requirement	3
Naphthalene	91-20-3	1.30E-06	1.33E-03	30%	9.10E-07	9.28E-04	AP-42 Table 3.1	2
PAH		2.20E-06	2.24E-03	30%	1.54E-06	1.57E-03	AP-42 Table 3.1	2
Propylene Oxide	75-56-9	2.90E-05	2.96E-02	30%	2.03E-05	2.07E-02	AP-42 Table 3.1	2
Toluene	108-88-3	1.30E-04	1.33E-01	30%	9.10E-05	9.28E-02	AP-42 Table 3.1	2
Xylenes	1330-20-7	6.40E-05	6.53E-02	30%	4.48E-05	4.57E-02	AP-42 Table 3.1	2

1. Controlled emission factors (oxidation catalyst) for Acetaldehyde, Acrolein and Benzene are obtained from U.S. EPA's Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines.

2. Emission factors for 1,3- Butadiene, Acetaldehyde, Ethylbenzene, Propylene Oxide, Toluene, Xylenes, Naphthalene and PAH are obtained from AP-42 Chapter 3.1, Table 3.1-3 (Stationary Gas Turbines, April, 2000). A control efficiency of 30% was applied to these uncontrolled/controlled emission factors based on expected VOM control efficiency from catalytic oxidation.

3. See EKPC requirement above for formaldehyde that sets the CT post-oxidation catalyst EF.

4. The control efficiencies are estimates and should not be construed as guarantees.

4.4 Derivation and Documentation of Steady-State Operation Emission Factors for 18-02

4.4.1 NSR-Regulated Pollutants

> Controlled emission factors (EFs) for all NSR-regulated pollutants have been calculated based on the worst-case hourly emissions profile from vendor specifications. Lead emissions are discussed in the HAP subsection below.

NO_X

Concentration in stack exhaust after SCR	4.5	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Factor	0.018	lb/MMBtu	= 46.27 lb/hr / 2,597 MMBtu/hr
Controlled Emission Rate	46.27	lb/hr	Maximum lb/hr from vendor specs for FO firing (Siemens Case 203)
Control Efficiency (**not guaranteed**)	82.00	%	Control offered by vendor specs FO firing cases only
Uncontrolled Emission Factor	0.099	lb/MMBtu	= 46.27 lb/hr / 2597 MMBtu/hr / (1 - 82%)
	13.483	lb/Mgal	= 9.90E-02 lb/MMBtu * 136.20 MMBtu/Mgal

CO

Concentration in stack exhaust after oxidation catalyst	2.0	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Factor	0.005	lb/MMBtu	= 12.52 lb/hr / 2,597 MMBtu/hr
Controlled Emission Rate	12.52	lb/hr	Maximum lb/hr from vendor specs for FO firing (Siemens Case 203)
Control Efficiency (**not guaranteed**)	50.00	%	Minimum control offered by vendor specs FO firing cases only
Uncontrolled Emission Factor	0.010	lb/MMBtu	= 12.52 lb/hr / 2597 MMBtu/hr / (1 - 50%)
	1.313	lb/Mgal	= 9.64E-03 lb/MMBtu * 136.20 MMBtu/Mgal

VOC

Concentration in Stack Exhaust	1.0	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Controlled Emission Factor	0.0014	lb/MMBtu	= 3.58 lb/hr / 2,597 MMBtu/hr
Controlled Emission Rate	3.58	lb/hr	Maximum lb/hr from vendor specs for FO firing (Siemens Case 203)
Control Efficiency (**not guaranteed**)	30.00	%	Conservative Estimate
Uncontrolled Emission Factor	0.0020	lb/MMBtu	= 03.58 lb/hr / 2597 MMBtu/hr / (1 - 30%)
	0.269	lb/Mgal	= 1.97E-03 lb/MMBtu * 136.20 MMBtu/Mgal

SO_2

> The following estimate is based solely on the sulfur content-based AP-42 emission factor for fuel oil-fired turbines, a maximum sulfur input of 15 ppm, and 100% conversion from S to SO_2. In reality, the SO_2 should be reduced by the amount of SO_2 converted to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the following methodology does not account for these further reductions and thus the emission estimates are conservative.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF * 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.2065	lb/Mgal	= 1.52E-03 lb/MMBtu * 136.20 MMBtu/Mgal
Maximum SO_2 emission rate:	3.94	lb/hr	= 1.52E-03 lb/MMBtu * 2,597 MMBtu/hr

H_2SO_4

> Within the combustion process, SO_2 can be further oxidized into SO_3, which then can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. 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, acid dew point, etc.

Uncontrolled Emission Rate of H_2SO_4	6.03	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 203)
Uncontrolled Emission Factor of H_2SO_4	2.32E-03	lb/MMBtu	= 6.03 lb/hr / 2,597 MMBtu/hr
Uncontrolled Emission Factor of H_2SO_4	0.316	lb/Mgal	= 2.32E-03 lb/MMBtu * 136.20 MMBtu/Mgal

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from this CCGT system. When EKPC asked each vendor to provide PM estimates, all vendors provided overly conservative estimates of PM (not guarantees). Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is a possibility under certain conditions. One pathway is the sulfate formation from H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$, as well as the nitrate formation in the form of NH_4NO_3. However, the PM emissions from these pathways are still expected to be low. Regardless, given uncertainties, EKPC conservatively used the information provided by the vendors for defining PM emissions. In all cases, all PM can be assumed to be less than 2.5 μm in mean diameter (i.e., PM = PM_{10} = $PM_{2.5}$).

Uncontrolled Emission Factor	0.0116	lb/MMBtu	= 30.118 lb/hr / 2,597 MMBtu/hr
Uncontrolled Emission Rate	30.12	lb/hr	Maximum lb/hr from vendor specs for FO firing (Siemens Case 203)
Uncontrolled Emission Factor	1.580	lb/Mgal	= 1.16E-02 lb/MMBtu * 136.20 MMBtu/Mgal

Greenhouse Gases

> Emission factors for GHGs are based on Subpart C of EPA's Greenhouse Gas Reporting Program (GHGRP, 40 CFR 98 Subpart C Table C-1 and Table C-2).
> The global warming multiplying factors for CH_4 and N_2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO_2e emissions.

CO_2

Uncontrolled Emission Factor	163.05	lb/MMBtu	40 CFR 98, Subpart C, Table C-1; converted from 73.96 kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	22,501	lb/Mgal	= 163.0539 lb/MMBtu * 138.00 MMBtu/Mgal per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	428,996	lb/hr	= 22,501.4 lb/Mgal * 19.065 MGal/hr

CH_4

Uncontrolled Emission Factor	0.0066	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 3.0 x 10^{-3} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	0.913	lb/Mgal	= 0.0066 lb/MMBtu * 138.00 MMBtu/Mgal per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	17.4	lb/hr	= 0.913 lb/Mgal * 19.065 MGal/hr

N_2O

Uncontrolled Emission Factor	0.0013	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 6.0 x 10^{-4} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	0.183	lb/Mgal	= 0.0013 lb/MMBtu * 138.00 MMBtu/Mgal per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	3.5	lb/hr	= 0.183 lb/Mgal * 19.065 MGal/hr

CO_2e

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1		
CH_4	28		89 FR 42218, May 14, 2024
N_2O	265		89 FR 42218, May 14, 2024
Uncontrolled Emission Factor	163.59	lb/MMBtu	= (CO_2 EF * CO_2 GWP) + (CH_4 EF * CH_4 GWP) + (N_2O EF * N_2O GWP)
Uncontrolled Emission Factor	22,575	lb/Mgal	= 163.5896 lb/MMBtu * 138.00 MMBtu/Mgal per 40 CFR 98, Subpart C
Uncontrolled Emission Rate	430,406	lb/hr	= (CO_2 lb/hr * CO_2 GWP) + (CH_4 lb/hr * CH_4 GWP) + (N_2O lb/hr * N_2O GWP)

4.4.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	5	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement for CCGT
Uncontrolled Emission Factor	0.0073	lb/MMBtu	= 19.03 lb/hr / 2596.693 MMBtu/hr
Uncontrolled Emission Rate	19.03	lb/hr	Maximum lb/hr from vendor specs for NG firing (Siemens Case 203)
Uncontrolled Emission Factor	0.998	lb/Mgal	= 7.33E-03 lb/MMBtu * 136.20 MMBtu/Mgal

4.4.3 Hazardous Air Pollutants for CT

Formaldehyde

Concentration in stack exhaust	0.091	ppmvd @ 15% O_2	EKPC's vendor guarantee requirement per 40 CFR §63.6100 and Table 1 of NESHAP YYYY
Molecular weight of HCHO	30.031	lb/lbmol	
Oxygen based F-Factor	8,710	dscf/MMBtu	RM Method 19 determination of Fd factor for natural gas combustion can use a default value of 8,710, or use equations 19-13 through 19.15. EKPC chose to use the default Fd factor from RM Method 19.
Controlled Emission Rate	0.57	lb/hr	= 1.0 atm STD * 30.031 lb/lbmol HCHO / 0.7302 ft3-atm/lbmol-°R / 527.67°R STD * 0.091 ppmvd @ 15% O2 /1E6 * 8,710.0 dscf/MMBtu * (20.9/(20.9-15) * 2,597 MMBtu/hr
Controlled Emission Factor	0.0002	lb/MMBtu	= 0.57 lb/hr / 2596.693 MMBtu/hr
Controlled Emission Factor	0.030	lb/Mgal	= 0.0002 lb/MMBtu * 136.20 MMBtu/Mgal per EKPC

> Other than for formaldehyde (described above), emission factors for organic and metallic HAP emissions from distillate oil-fired turbines published in AP-42, Section 3.1 are used to estimate potential emissions.

4.4.4 Hazardous Air Pollutants for FO

> Emission factors for fuel oil combustion within the CCGT are obtained from AP-42, Chapter 3.1, Tables 3.1-4 and 3.1-5 (Emission Factors for Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines, April 2000).

Pollutant	CAS No.	GT Uncontrolled EF (lb/MMBtu)	GT Uncontrolled EF (lb/Mgal)	Oxidation Catalyst Control Efficiency[4] (%)	GT After Oxidation Catalyst EF (lb/MMBtu)	GT After Oxidation Catalyst EF (lb/Mgal)	Basis	Note
Benzene	71-43-2	5.5E-05	7.65E-03	30%	3.9E-05	5.35E-03	AP42 Table 3.1-4	1, 2
1,3-Butadiene	106-99-0	1.6E-05	2.22E-03	30%	1.1E-05	1.56E-03	AP42 Table 3.1-4	1, 2
Formaldehyde	50-00-0	2.8E-04	3.89E-02	22%	2.2E-04	3.0E-02	EKPC Requirement	3
Naphthalene	91-20-3	3.5E-05	4.87E-03	30%	2.5E-05	3.41E-03	AP42 Table 3.1-4	1, 2
PAH		4.0E-05	5.56E-03	30%	2.8E-05	3.89E-03	AP42 Table 3.1-4	1, 2
Arsenic	7440-38-2	1.1E-05	1.53E-03		1.1E-05	1.53E-03	AP42 Table 3.1-5	1
Beryllium	7440-41-7	3.1E-07	4.31E-05		3.1E-07	4.31E-05	AP42 Table 3.1-5	1
Cadmium	7440-43-9	4.8E-06	6.67E-04		4.8E-06	6.67E-04	AP42 Table 3.1-5	1
Chromium	7440-47-3	1.1E-05	1.53E-03		1.1E-05	1.53E-03	AP42 Table 3.1-5	1
Lead	7439-92-1	1.4E-05	1.95E-03		1.4E-05	1.95E-03	AP42 Table 3.1-5	1
Manganese	7439-96-5	7.9E-04	1.10E-01		7.9E-04	1.10E-01	AP42 Table 3.1-5	1
Mercury	7439-97-6	1.2E-06	1.67E-04		1.2E-06	1.67E-04	AP42 Table 3.1-5	1
Nickel	7440-02-0	4.6E-06	6.39E-04		4.6E-06	6.39E-04	AP42 Table 3.1-5	1
Selenium	7782-49-2	2.5E-05	3.48E-03		2.5E-05	3.48E-03	AP42 Table 3.1-5	1

1. Emission factors are obtained from AP-42, Chapter 3.1, Tables 3.1-4 and 3.1-5 (Emission Factors for Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines, April 2000).

2. Control efficiencies were applied to these uncontrolled emission factors based on expected VOM control efficiency from catalytic oxidation as described for HAP emissions from natural gas combustion.

3. See EKPC requirement for formaldehyde produced in the CT, as it applies to the entire CCGT.

4. The control efficiencies are estimates and should not be construed as guarantees.

4.5 CCGT Potential Emissions Summary - Steady State Operations

> The following represents two scenarios used to calculate potential emissions. Scenario 1 assumes that the CCGT combusts natural gas at 2,734 MMBtu/hr heat input for 7,680 hours per year, and combusts fuel oil at 2,597 MMBtu/hr heat input for 1,080 hours per year. No SU/SD events are considered in this first scenario. Scenario 2 assumes that the CCGT combusts natural gas at 2,734 MMBtu/hr heat input for 4,191 hours per year, and combusts fuel oil at 2,597 MMBtu/hr heat input for 861 hours per year. A conservative number of annual SU/SD events are used to derive the annual potential emissions for this second scenario.

Process ID 1: Steady-State Operation (NG Firing) (Scenario 1)

	Uncontrolled EF		Uncontrolled Emissions		~Control	Controlled Emissions	
	(lb/MMscf)	Basis	(lb/hr)	(tpy)	Efficiency	(lb/hr)	(tpy)
Regulated Pollutants							
NO_X	57.642	EKPC Calculated	148.7	570.9	86.7%	19.8	76.1
CO	9.359	EKPC Calculated	24.1	92.7	50.0%	12.1	46.4
VOC	1.914	EKPC Calculated	4.94	19.0	30.0%	3.46	13.3
PM	6.672	Vendor Estimate	17.2	66.1		17.2	66.1
PM_{10}	6.672	Vendor Estimate	17.2	66.1		17.2	66.1
$PM_{2.5}$	6.672	Vendor Estimate	17.2	66.1		17.2	66.1
SO_2	1.424	Pipeline spec conversion	3.67	14.1		3.67	14.1
H_2SO_4	2.181	Pipeline spec conversion	5.63	21.6		5.63	21.6
NH_3	7.113	EKPC Requirement	18.3	70.5		18.3	70.5
CO_2	120,019	40 CFR 98, Table C-1	309,584	1,188,803		309,584	1,188,803
CH_4	24.881	AP-42, Table 3.1-2a	64.2	246.5		64.2	246.5
N_2O	3.619	AP-42, Table 3.1-2a	9.3	35.8		9.3	35.8
CO_2e	121,674	40 CFR 98 Subpart A	313,855	1,205,203		313,855	1,205,203

		Uncontrolled EF		Uncontrolled Emissions		~Control	Controlled Emissions	
	CAS No.	(lb/MMscf)	Basis	(lb/hr)	(tpy)	Efficiency	(lb/hr)	(tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	4.39E-04	AP-42 Table 3.1	0.001	0.004	30%	0.001	0.003
Acetaldehyde	75-07-0	2.56E-01	AP-42 Table 3.1 & 3-4 of BID	0.662	2.540	30%	0.463	1.778
Acrolein	107-02-8	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	0.017	0.065	43%	0.010	0.037
Benzene	71-43-2	1.22E-02	AP-42 Table 3.1 & 3-4 of BID	0.032	0.121	73%	0.009	0.033
Ethylbenzene	100-41-4	3.26E-02	AP-42 Table 3.1	0.084	0.323	30%	0.059	0.226
Formaldehyde	50-00-0	7.24E-01	EKPC Requirement	1.868	7.173	68%	0.598	2.298
Naphthalene	91-20-3	1.33E-03	AP-42 Table 3.1	0.003	0.013	30%	0.002	0.009
PAH		2.24E-03	AP-42 Table 3.1	0.006	0.022	30%	0.004	0.016
Propylene Oxide	75-56-9	2.96E-02	AP-42 Table 3.1	0.076	0.293	30%	0.053	0.205
Toluene	108-88-3	1.33E-01	AP-42 Table 3.1	0.342	1.31	30%	0.239	0.92
Xylenes	1330-20-7	6.53E-02	AP-42 Table 3.1	0.168	0.65	30%	0.118	0.45
Total HAP		1.264	Sum of HAPs	3.259	12.515	52%	1.556	5.98

Process ID 2: Steady-State Operation (FO Firing) (Scenario 1)

	Uncontrolled EF (lb/Mgal)	Basis	Uncontrolled Emissions (lb/hr)	(tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	(tpy)
Regulated Pollutants							
NO_X	13.483	EKPC Calculated	257.1	138.8	82.0%	46.3	25.0
CO	1.313	EKPC Calculated	25.0	13.5	50.0%	12.5	6.8
VOC	0.269	EKPC Calculated	5.12	2.8	30.0%	3.58	1.9
PM	1.580	Vendor Estimate	30.1	16.3		30.1	16.3
PM_{10}	1.580	Vendor Estimate	30.1	16.3		30.1	16.3
$PM_{2.5}$	1.580	Vendor Estimate	30.1	16.3		30.1	16.3
SO_2	0.207	ULSD spec conversion	3.94	2.1		3.94	2.1
H_2SO_4	0.316	ULSD spec conversion	6.03	3.3		6.03	3.3
NH_3	0.998	EKPC Requirement	19.0	10.3		19.0	10.3
CO_2	22,501	40 CFR 98, Table C-1	428,996	231,658		428,996	231,658
CH_4	0.913	AP-42, Table 3.1-2a	17.4	9.4		17.4	9.4
N_2O	0.183	AP-42, Table 3.1-2a	3.5	1.9		3.5	1.9
CO_2e	22,575	40 CFR 98 Subpart A	430,406	232,419		430,406	232,419

	CAS No.	Uncontrolled EF (lb/Mgal)	Basis	Uncontrolled Emissions (lb/hr)	(tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	(tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	2.22E-03	AP42 Table 3.1-4	0.042	0.023	30%	0.030	0.016
Benzene	71-43-2	7.65E-03	AP42 Table 3.1-4	0.146	0.079	30%	0.102	0.055
Formaldehyde	50-00-0	2.98E-02	EKPC Requirement	0.568	0.307	22%	0.444	0.240
Naphthalene	91-20-3	4.87E-03	AP42 Table 3.1-4	0.093	0.050	30%	0.065	0.035
PAH		5.56E-03	AP42 Table 3.1-4	0.106	0.057	30%	0.074	0.040
Arsenic	7440-38-2	1.53E-03	AP42 Table 3.1-5	0.029	0.016		0.029	0.016
Beryllium	7440-41-7	4.31E-05	AP42 Table 3.1-5	0.001	0.000		0.001	0.000
Cadmium	7440-43-9	6.67E-04	AP42 Table 3.1-5	0.013	0.007		0.013	0.007
Chromium	7440-47-3	1.53E-03	AP42 Table 3.1-5	0.029	0.016		0.029	0.016
Lead	7439-92-1	1.95E-03	AP42 Table 3.1-5	0.037	0.020		0.037	0.0200
Manganese	7439-96-5	1.10E-01	AP42 Table 3.1-5	2.094	1.131		2.094	1.131
Mercury	7439-97-6	1.67E-04	AP42 Table 3.1-5	0.003	0.00		0.003	0.00
Nickel	7440-02-0	6.39E-04	AP42 Table 3.1-5	0.012	0.01		0.012	0.01
Selenium	7782-49-2	3.48E-03	AP42 Table 3.1-5	0.066	0.036		0.066	0.04
Total HAP		0.170	Sum of HAPs	3.239	1.749	7%	2.999	1.620

Process ID 1: Steady-State Operation (NG Firing) (Scenario 2)

	Uncontrolled EF (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Regulated Pollutants							
NO_X	57.642	EKPC Calculated	148.7	311.6	86.7%	19.8	41.5
CO	9.359	EKPC Calculated	24.1	50.6	50.0%	12.1	25.3
VOC	1.914	EKPC Calculated	4.94	10.3	30.0%	3.46	7.2
PM	6.672	Vendor Estimate	17.2	36.1		17.2	36.1
PM_{10}	6.672	Vendor Estimate	17.2	36.1		17.2	36.1
$PM_{2.5}$	6.672	Vendor Estimate	17.2	36.1		17.2	36.1
SO_2	1.424	Pipeline spec conversion	3.67	7.7		3.67	7.7
H_2SO_4	2.181	Pipeline spec conversion	5.63	11.8		5.63	11.8
NH_3	7.113	EKPC Requirement	18.3	38.4		18.3	38.4
CO_2	120,019	40 CFR 98, Table C-1	309,584	648,772		309,584	648,772
CH_4	24.881	AP-42, Table 3.1-2a	64.2	134.5		64.2	134.5
N_2O	3.619	AP-42, Table 3.1-2a	9.3	19.6		9.3	19.6
CO_2e	121,674	40 CFR 98 Subpart A	313,855	657,722		313,855	657,722

	CAS No.	Uncontrolled EF (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	4.39E-04	AP-42 Table 3.1	0.001	0.002	30%	0.001	0.002
Acetaldehyde	75-07-0	2.56E-01	AP-42 Table 3.1 & 3-4 of BID	0.662	1.386	30%	0.463	0.970
Acrolein	107-02-8	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	0.017	0.035	43%	0.010	0.020
Benzene	71-43-2	1.22E-02	AP-42 Table 3.1 & 3-4 of BID	0.032	0.066	73%	0.009	0.018
Ethylbenzene	100-41-4	3.26E-02	AP-42 Table 3.1	0.084	0.176	30%	0.059	0.124
Formaldehyde	50-00-0	7.24E-01	EKPC Requirement	1.868	3.915	68%	0.598	1.254
Naphthalene	91-20-3	1.33E-03	AP-42 Table 3.1	0.003	0.007	30%	0.002	0.005
PAH		2.24E-03	AP-42 Table 3.1	0.006	0.012	30%	0.004	0.008
Propylene Oxide	75-56-9	2.96E-02	AP-42 Table 3.1	0.076	0.160	30%	0.053	0.112
Toluene	108-88-3	1.33E-01	AP-42 Table 3.1	0.342	0.72	30%	0.239	0.50
Xylenes	1330-20-7	6.53E-02	AP-42 Table 3.1	0.168	0.35	30%	0.118	0.25
Total HAP		1.264	Sum of HAPs	3.259	6.830	52%	1.556	3.262

Process ID 2: Steady-State Operation (FO Firing) (Scenario 2)

	Uncontrolled EF (lb/Mgal)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Regulated Pollutants							
NO_X	13.483	EKPC Calculated	257.1	110.7	82.0%	46.3	19.9
CO	1.313	EKPC Calculated	25.0	10.8	50.0%	12.5	5.4
VOC	0.269	EKPC Calculated	5.12	2.2	30.0%	3.58	1.5
PM	1.580	Vendor Estimate	30.1	13.0		30.1	13.0
PM_{10}	1.580	Vendor Estimate	30.1	13.0		30.1	13.0
$PM_{2.5}$	1.580	Vendor Estimate	30.1	13.0		30.1	13.0
SO_2	0.207	ULSD spec conversion	3.94	1.7		3.94	1.7
H_2SO_4	0.316	ULSD spec conversion	6.03	2.6		6.03	2.6
NH_3	0.998	EKPC Requirement	19.0	8.2		19.0	8.2
CO_2	22,501	40 CFR 98, Table C-1	428,996	184,737		428,996	184,737
CH_4	0.913	AP-42, Table 3.1-2a	17.4	7.5		17.4	7.5
N_2O	0.183	AP-42, Table 3.1-2a	3.5	1.5		3.5	1.5
CO_2e	22,575	40 CFR 98 Subpart A	430,406	185,344		430,406	185,344

	CAS No.	Uncontrolled EF (lb/Mgal)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	2.22E-03	AP42 Table 3.1-4	0.042	0.018	30%	0.030	0.013
Benzene	71-43-2	7.65E-03	AP42 Table 3.1-4	0.146	0.063	30%	0.102	0.044
Formaldehyde	50-00-0	2.98E-02	EKPC Requirement	0.568	0.245	22%	0.444	0.191
Naphthalene	91-20-3	4.87E-03	AP42 Table 3.1-4	0.093	0.040	30%	0.065	0.028
PAH		5.56E-03	AP42 Table 3.1-4	0.106	0.046	30%	0.074	0.032
Arsenic	7440-38-2	1.53E-03	AP42 Table 3.1-5	2.92E-02	1.26E-02		2.92E-02	1.26E-02
Beryllium	7440-41-7	4.31E-05	AP42 Table 3.1-5	8.22E-04	3.54E-04		8.22E-04	3.54E-04
Cadmium	7440-43-9	6.67E-04	AP42 Table 3.1-5	1.27E-02	5.48E-03		1.27E-02	5.48E-03
Chromium	7440-47-3	1.53E-03	AP42 Table 3.1-5	2.92E-02	1.26E-02		2.92E-02	1.26E-02
Lead	7439-92-1	1.95E-03	AP42 Table 3.1-5	3.71E-02	1.60E-02		3.71E-02	1.60E-02
Manganese	7439-96-5	1.10E-01	AP42 Table 3.1-5	2.09E+00	9.02E-01		2.09E+00	9.02E-01
Mercury	7439-97-6	1.67E-04	AP42 Table 3.1-5	3.18E-03	1.37E-03		3.18E-03	1.37E-03
Nickel	7440-02-0	6.39E-04	AP42 Table 3.1-5	1.22E-02	5.25E-03		1.22E-02	5.25E-03
Selenium	7782-49-2	3.48E-03	AP42 Table 3.1-5	6.63E-02	2.85E-02		6.63E-02	2.85E-02
Total HAP		0.170	Sum of HAPs	3.239	1.395	7%	2.999	1.291

4.6 Capacity and Underlying Assumptions for Cold, Warm, Hot, and Shutdown Events

> Refer to the operating scenarios outlined in Section 5 for the derivations of maximum annual startup and shutdown events used to develop the worst-case annual potential emissions profile.

SU/SD Definitions and Frequencies			Min. time in between event and SD	Event Duration
> Cold start defined as taking place >48 hours after the previous shutdown				
Maximum Annual Cold Start Events (NG)	15 events/yr	100 min NG/C-SU	48 hr of SD	1.67 hr
Maximum Annual Cold Start Events (FO)	15 events/yr	110 min FO/C-SU		1.83 hr
> Warm start cool down duration ranges from >8 to <48 hours after shutdown. Assume 48 hours.				
Maximum Annual Warm Start Events (NG)	365 events/yr	70 min NG/W-SU	8 hr of SD	1.17 hr
Maximum Annual Warm Start Events (FO)	15 events/yr	75 min FO/W-SU		1.25 hr
> Hot starts are defined as taking place within 8 hours of the previous shutdown.				
Maximum Annual Hot Start Events (NG)	585 events/yr	45 min NG/H-SU	0 hr of SD	0.75 hr
Maximum Annual Hot Start Events (FO)	30 events/yr	45 min FO/H-SU		0.75 hr
> Shutdowns precede each startup; as such, the total number of shutdowns per year equals the sum of all cold, warm and hot starts				
Maximum Annual Shutdown Events (NG)	965 events/yr	30 min/NG SD		0.50 hr
Maximum Annual Shutdown Events (FO)	60 events/yr	30 min/FO SD		0.50 hr

4.6.1 Startup and Shutdown Event Emission Factors

> The EFs presented below for emissions of NSR-regulated pollutants from startup and shutdown events are based on the highest vendor-provided lb/event.

Natural Gas Operations

Event Type	NO_X EF (lb/event)	CO EF (lb/event)	VOC EF (lb/event)	$PM/PM_{10}/PM_{2.5}$ EF (lb/event)	SO_2 EF (lb/event)	H_2SO_4 EF (lb/event)	CO_2 EF (lb/event)
Cold Start	288.0	9,358.0	824.0	15.0	3.2	1.1	192,828
Warm Start	159.0	4,501.0	410.0	9.0	1.9	0.7	123,038
Hot Start	110.0	2,677.0	253.0	7.0	1.5	0.5	96,867
Shutdown	56.0	849.0	64.0	3.0	0.6	0.2	66,924

Fuel Oil Operations

Event Type	NO_X EF (lb/event)	CO EF (lb/event)	VOC EF (lb/event)	$PM/PM_{10}/PM_{2.5}$ EF (lb/event)	SO_2 EF (lb/event)	H_2SO_4 EF (lb/event)	CO_2 EF (lb/event)
Cold Start	556.0	15,416.0	1,780.0	22.0	2.9	1.0	252,300
Warm Start	310.0	7,462.0	872.0	13.0	1.7	0.6	162,553
Hot Start	217.0	4,477.0	530.0	10.0	1.3	0.5	128,897
Shutdown	100.0	1,215.0	122.0	5.0	0.7	0.2	82,687

4.7 GT Cold, Warm, & Hot Startups, and Shutdown Potential Emissions Summary (Natural Gas)

> The following potential emissions represent the maximum pounds per SUSD event by pollutant.

Pollutant	Uncontrolled EF (lb/event)	Basis	Uncontrolled Emissions (lb/yr)	Uncontrolled Emissions (tpy)	Control Efficiency	Controlled Emissions (lb/yr)	Controlled Emissions (tpy)
Process ID 3: Cold Startups							
NO_X	288.0	Vendor Estimate	4,320	2.16	N/A	4,320	2.16
CO	9,358.0	Vendor Estimate	140,370	70.19	N/A	140,370	70.19
VOC	824.0	Vendor Estimate	12,360	6.18	N/A	12,360	6.18
PM	15.0	Vendor Estimate	225	0.11	N/A	225	0.11
PM_{10}	15.0	Vendor Estimate	225	0.11	N/A	225	0.11
$PM_{2.5}$	15.0	Vendor Estimate	225	0.11	N/A	225	0.11
SO_2	3.2	Vendor Estimate	48	0.02	N/A	48	0.02
H_2SO_4	1.1	Vendor Estimate	17	0.01	N/A	17	0.01
CO_2	192,828	Vendor Estimate	2,892,420	1,446.2	N/A	2,892,420	1,446.2
Process ID 4: Warm Startups							
NO_X	159.0	Vendor Estimate	58,035	29.02	N/A	58,035	29.02
CO	4,501.0	Vendor Estimate	1,642,865	821.43	N/A	1,642,865	821.43
VOC	410.0	Vendor Estimate	149,650	74.83	N/A	149,650	74.83
PM	9.0	Vendor Estimate	3,285	1.64	N/A	3,285	1.64
PM_{10}	9.0	Vendor Estimate	3,285	1.64	N/A	3,285	1.64
$PM_{2.5}$	9.0	Vendor Estimate	3,285	1.64	N/A	3,285	1.64
SO_2	1.9	Vendor Estimate	701	0.35	N/A	701	0.35
H_2SO_4	0.7	Vendor Estimate	247	0.12	N/A	247	0.12
CO_2	123,038.0	Vendor Estimate	44,908,870	22,454.4	N/A	44,908,870	22,454.4
Process ID 5: Hot Startups							
NO_X	110.0	Vendor Estimate	64,350	32.18	N/A	64,350	32.18
CO	2,677.0	Vendor Estimate	1,566,045	783.02	N/A	1,566,045	783.02
VOC	253.0	Vendor Estimate	148,005	74.00	N/A	148,005	74.00
PM	7.0	Vendor Estimate	4,095	2.05	N/A	4,095	2.05
PM_{10}	7.0	Vendor Estimate	4,095	2.05	N/A	4,095	2.05
$PM_{2.5}$	7.0	Vendor Estimate	4,095	2.05	N/A	4,095	2.05
SO_2	1.5	Vendor Estimate	874	0.44	N/A	874	0.44
H_2SO_4	0.5	Vendor Estimate	308	0.15	N/A	308	0.15
CO_2	96,867.0	Vendor Estimate	56,667,195	28,333.6	N/A	56,667,195	28,333.6

Pollutant	Uncontrolled EF (lb/event)	Basis	Uncontrolled Emissions (lb/yr)	(tpy)	Control Efficiency	Controlled Emissions (lb/yr)	(tpy)
Process ID 6: Shutdowns							
NO_X	56.0	Vendor Estimate	54,040	27.02	N/A	54,040	27.02
CO	849.0	Vendor Estimate	819,285	409.64	N/A	819,285	409.64
VOC	64.0	Vendor Estimate	61,760	30.88	N/A	61,760	30.88
PM	3.0	Vendor Estimate	2,895	1.45	N/A	2,895	1.45
PM_{10}	3.0	Vendor Estimate	2,895	1.45	N/A	2,895	1.45
$PM_{2.5}$	3.0	Vendor Estimate	2,895	1.45	N/A	2,895	1.45
SO_2	0.6	Vendor Estimate	618	0.31	N/A	618	0.31
H_2SO_4	0.2	Vendor Estimate	218	0.11	N/A	218	0.11
CO_2	66,924.0	Vendor Estimate	64,581,660	32,290.8	N/A	64,581,660	32,290.8

4.8 GT Cold, Warm, & Hot Startups, and Shutdown Potential Emissions Summary (Fuel Oil)

> The following potential emissions represent the maximum pounds per SUSD event by pollutant.

Pollutant	Uncontrolled EF (lb/event)	Basis	Uncontrolled Emissions (lb/yr)	(tpy)	Control Efficiency	Controlled Emissions (lb/yr)	(tpy)
Process ID 7: Cold Startups							
NO_X	556.0	Vendor Estimate	8,340	4.17	N/A	8,340	4.17
CO	15,416.0	Vendor Estimate	231,240	115.62	N/A	231,240	115.62
VOC	1,780.0	Vendor Estimate	26,700	13.35	N/A	26,700	13.35
PM	22.0	Vendor Estimate	330	0.17	N/A	330	0.17
PM_{10}	22.0	Vendor Estimate	330	0.17	N/A	330	0.17
$PM_{2.5}$	22.0	Vendor Estimate	330	0.17	N/A	330	0.17
SO_2	2.9	Vendor Estimate	43	0.02	N/A	43	0.02
H_2SO_4	1.0	Vendor Estimate	15	0.01	N/A	15	0.01
CO_2	252,300.0	Vendor Estimate	3,784,500	1,892.3	N/A	3,784,500	1,892.3
Process ID 8: Warm Startups							
NO_X	310.0	Vendor Estimate	4,650	2.33	N/A	4,650	2.33
CO	7,462.0	Vendor Estimate	111,930	55.97	N/A	111,930	55.97
VOC	872.0	Vendor Estimate	13,080	6.54	N/A	13,080	6.54
PM	13.0	Vendor Estimate	195	0.10	N/A	195	0.10
PM_{10}	13.0	Vendor Estimate	195	0.10	N/A	195	0.10
$PM_{2.5}$	13.0	Vendor Estimate	195	0.10	N/A	195	0.10
SO_2	1.7	Vendor Estimate	25	0.01	N/A	25	0.01
H_2SO_4	0.6	Vendor Estimate	9	0.00	N/A	9	0.00
CO_2	162,553.0	Vendor Estimate	2,438,295	1,219.1	N/A	2,438,295	1,219.1

Process ID 9: Hot Startups							
NO_X	217.0	Vendor Estimate	6,510	3.26	N/A	6,510	3.26
CO	4,477.0	Vendor Estimate	134,310	67.16	N/A	134,310	67.16
VOC	530.0	Vendor Estimate	15,900	7.95	N/A	15,900	7.95
PM	10.0	Vendor Estimate	300	0.15	N/A	300	0.15
PM_{10}	10.0	Vendor Estimate	300	0.15	N/A	300	0.15
$PM_{2.5}$	10.0	Vendor Estimate	300	0.15	N/A	300	0.15
SO_2	1.3	Vendor Estimate	39	0.02	N/A	39	0.02
H_2SO_4	0.5	Vendor Estimate	14	0.01	N/A	14	0.01
CO_2	128,897.0	Vendor Estimate	3,866,910	1,933.5	N/A	3,866,910	1,933.5
Process ID 10: Shutdowns							
NO_X	100.0	Vendor Estimate	6,000	3.00	N/A	6,000	3.00
CO	1,215.0	Vendor Estimate	72,900	36.45	N/A	72,900	36.45
VOC	122.0	Vendor Estimate	7,320	3.66	N/A	7,320	3.66
PM	5.0	Vendor Estimate	300	0.15	N/A	300	0.15
PM_{10}	5.0	Vendor Estimate	300	0.15	N/A	300	0.15
$PM_{2.5}$	5.0	Vendor Estimate	300	0.15	N/A	300	0.15
SO_2	0.7	Vendor Estimate	39	0.02	N/A	39	0.02
H_2SO_4	0.2	Vendor Estimate	14	0.01	N/A	14	0.01
CO_2	82,687.0	Vendor Estimate	4,961,220	2,480.6	N/A	4,961,220	2,480.6

4.9 CCGT Overall Combined PTE Summary - Steady State Operations vs Worst-Case Annual SU/SD Events

> The table below summarizes the PTE from all Process IDs. The Scenario 1 column represents PTE from 8,760 hours at normal or steady-state operations, which includes 7,680 hr/yr firing NG and 1,080 hr/yr firing FO. The Scenario 2 column represents PTE from conservative but realistic scenarios for startups, shutdowns, and backup fuel oil operation. The Scenario 3 column represents PTE from 8,760 hours at steady-state NG firing.

> The PTE below is representative of one CCGT.

Pollutant	PTE (tpy)	Scenario 1 (tpy)	Scenario 2 (tpy)	Scenario 3 (tpy)	Worst-Case Scenario
NO_X	164.6	101.1	164.6	86.8	Scenario 2
CO	2,390.2	53.1	2,390.2	52.9	Scenario 2
VOC	226.2	15.2	226.2	15.1	Scenario 2
PM	82.4	82.4	54.8	75.4	Scenario 1
PM_{10}	82.4	82.4	54.8	75.4	Scenario 1
$PM_{2.5}$	82.4	82.4	54.8	75.4	Scenario 1
SO_2	16.2	16.2	10.6	16.1	Scenario 1
H_2SO_4	24.9	24.9	14.8	24.6	Scenario 1
NH_3	80.7	80.7	46.6	80.4	Scenario 1
CO_2e	1,437,622	1,437,622	843,066	1,374,685	Scenario 1
1,3-Butadiene	1.91E-02	1.91E-02	1.44E-02	3.47E-03	Scenario 1
Acetaldehyde	1.78	1.78	0.97	2.03	Scenario 1
Acrolein	3.66E-02	3.66E-02	2.00E-02	4.17E-02	Scenario 1
Benzene	8.80E-02	8.80E-02	6.19E-02	3.76E-02	Scenario 1
Ethylbenzene	0.23	0.23	0.12	0.26	Scenario 1
Formaldehyde	2.54	2.54	1.45	2.62	Scenario 1
Naphthalene	4.43E-02	4.43E-02	3.30E-02	1.05E-02	Scenario 1
PAH	5.56E-02	5.56E-02	4.04E-02	1.77E-02	Scenario 1
Propylene Oxide	0.21	0.21	0.11	0.23	Scenario 1
Toluene	0.92	0.92	0.50	1.05	Scenario 1
Xylenes	0.45	0.45	0.25	0.52	Scenario 1
Arsenic	1.57E-02	1.57E-02	1.26E-02	0	Scenario 1
Beryllium	4.44E-04	4.44E-04	3.54E-04	0	Scenario 1
Cadmium	6.87E-03	6.87E-03	5.48E-03	0	Scenario 1
Chromium	1.57E-02	1.57E-02	1.26E-02	0	Scenario 1
Lead	2.00E-02	2.00E-02	1.60E-02	0	Scenario 1
Manganese	1.13	1.13	0.90	0	Scenario 1
Mercury	1.72E-03	1.72E-03	1.37E-03	0	Scenario 1
Nickel	6.58E-03	6.58E-03	5.25E-03	0	Scenario 1
Selenium	3.58E-02	3.58E-02	2.85E-02	0	Scenario 1
Total HAP	7.6	7.6	4.6	6.8	Scenario 1

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Client EKPC
Project Cooper CCGT — Date: 12/12/2024
2x1 5000F Wet Cooled Combined Cycle — Revision: L

Case #		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Case Description		Unfired 2x100% -7.6°F Evap OFF NG	Unfired 2x100% 6.5°F Evap OFF NG	Unfired 2x100% 40.3°F Evap OFF NG	Unfired 2x100% 56.2°F Evap OFF NG	Unfired 2x100% 59°F Evap OFF NG	Unfired 2x100% 71.9°F Evap OFF NG	Unfired 2x100% 86.6°F Evap OFF NG
Ambient Temperature		-7.6 F	6.5 F	40.3 F	56.2 F	59 F	71.9 F	86.6 F
Gas Turbine Load		100%	100%	100%	100%	100%	100%	100%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Ambient Conditions								
Temperature	degree F	-7.6	6.5	40.3	56.2	59	71.9	86.6
Relative Humidity	%	38%	38%	60%	72%	73%	60%	76%
Wet Bulb Temperature	degree F	-9.1	3.7	35.1	51.3	54.0	62.5	80.0
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)								
Electrical Output	kW	265,579	265,560	265,515	265,490	265,488	254,681	238,327
Heat Rate - LHV	Btu/kWh	9,229	9,200	9,200	9,272	9,295	9,396	9,565
Heat Rate - HHV	Btu/kWh	10,226	10,194	10,193	10,273	10,299	10,411	10,597
GTG Heat Input- LHV	MMBtu/hr	2,451	2,443	2,443	2,461	2,468	2,393	2,280
GTG Heat Input- HHV	MMBtu/hr	2,716	2,707	2,706	2,727	2,734	2,651	2,526
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	5,003,159	4,995,183	5,030,289	5,108,228	5,141,674	5,008,959	4,778,953
Exhaust Temperature	degree F	1,094	1,101	1,117	1,124	1,124	1,135	1,153
Steam Turbine Generator Performance								
Electrical Output	kW	239,869	242,563	252,354	259,366	261,024	257,301	249,663
Duct Burner Fuel Consumption								
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet								
Ar	%	0.89%	0.89%	0.89%	0.88%	0.88%	0.88%	0.86%
CO_2	%	4.16%	4.15%	4.12%	4.08%	4.06%	4.04%	4.00%
H_2O	%	7.92%	7.94%	8.30%	8.82%	8.92%	9.22%	10.80%
N_2	%	74.98%	74.96%	74.65%	74.21%	74.13%	73.87%	72.62%
O_2	%	12.04%	12.05%	12.04%	12.00%	12.01%	11.99%	11.71%
Stack Emissions at Exit								
NOx Emissions								
NOx,@15% O2 Into SCR	ppmvd	15.0	15.0	15.0	15.0	15.0	15.0	15.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	147.7	147.2	147.2	148.3	148.7	144.2	137.3
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	19.7	19.6	19.6	19.8	19.8	19.2	18.3
SCR NOx Removal Efficiency	%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%
NH3 Emissions								
NH3 Reacted with NOx (per HRSG)	lb/hr	61.6	61.4	61.4	61.9	62.0	60.1	57.3
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	18.2	18.2	18.2	18.3	18.3	17.8	16.9

Case #		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Case Description		Unfired 2x100% -7.6°F Evap OFF NG	Unfired 2x100% 6.5°F Evap OFF NG	Unfired 2x100% 40.3°F Evap OFF NG	Unfired 2x100% 56.2°F Evap OFF NG	Unfired 2x100% 59°F Evap OFF NG	Unfired 2x100% 71.9°F Evap OFF NG	Unfired 2x100% 86.6°F Evap OFF NG
CO Emissions								
CO into catalyst	ppmvd	5.3	5.3	5.3	5.2	5.2	5.2	5.3
CO into catalyst, @ 15% O2	ppmvd	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO into catalyst (per HRSG)	lb/hr	24.0	23.9	23.9	24.1	24.1	23.4	22.3
CO out of catalyst	ppmvd	2.65	2.64	2.63	2.62	2.61	2.60	2.63
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	12.0	12.0	11.9	12.0	12.1	11.7	11.1
CO Catalyst Removal Efficiency	%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
SO2 Emissions								
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.245	0.245	0.244	0.243	0.242	0.242	0.237
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.266	0.266	0.266	0.266	0.266	0.266	0.266
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	3.6	3.6	3.6	3.7	3.7	3.6	3.4
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134
Volatile Organic Compounds								
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	3.4	3.4	3.4	3.4	3.5	3.4	3.2
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	14.1	14.0	14.1	14.2	14.3	13.8	13.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	16.5	16.4	16.5	16.6	16.7	16.2	15.4
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00607	0.00607	0.00609	0.00610	0.00612	0.00611	0.00610
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	12.6	12.6	12.6	12.8	12.8	12.4	11.8
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	15.0	15.0	15.0	15.2	15.3	14.8	14.1
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00554	0.00554	0.00556	0.00557	0.00559	0.00558	0.00557
H2SO4 Emissions								
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	5.59	5.57	5.57	5.61	5.63	5.46	5.20
H2SO4 in Exhaust Gas	lb/MMBtu	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206
GHG Emissions								
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	317,673	316,667	316,585	319,029	319,843	310,163	295,442
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	824.0	818.6	808.3	807.3	807.7	809.1	813.5
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	149.7	149.2	149.2	150.3	150.7	146.1	139.2
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	178.4	177.8	177.8	179.2	179.6	174.2	165.9
GHG in Exhaust Gas (per HRSG)	lb/hr	318,001	316,994	316,912	319,358	320,173	310,484	295,747
Stack Exit								
Temperature	degree F	177	177	179	182	182	183	182
Flow Rate (per HRSG)	lb/hr	5,003,159	4,995,183	5,030,289	5,108,228	5,141,674	5,008,959	4,778,953
Flow Rate (per HRSG)	scfm	1,009,789	1,008,284	1,016,914	1,034,872	1,042,074	1,016,464	975,834
Flow Rate (per HRSG)	acfm	1,275,209	1,272,079	1,287,726	1,316,678	1,326,331	1,296,322	1,242,408
Stack Velocity	ft/sec	62.8	62.7	63.5	64.9	65.4	63.9	61.2
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8

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Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 8	Case 9	Case 19	Case 20	Case 21	Case 22	Case 23
Case Description		Unfired 2x100% 95.7°F Evap OFF NG	Unfired 2x100% 104.7°F Evap OFF NG	Unfired 2x75% -7.6°F Evap OFF NG	Unfired 2x75% 6.5°F Evap OFF NG	Unfired 2x75% 40.3°F Evap OFF NG	Unfired 2x75% 56.2°F Evap OFF NG	Unfired 2x75% 59°F Evap OFF NG
Ambient Temperature		95.7 F	104.7 F	-7.6 F	6.5 F	40.3 F	56.2 F	59 F
Gas Turbine Load		100%	100%	75%	75%	75%	75%	75%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Ambient Conditions								
Temperature	degree F	95.7	104.7	-7.6	6.5	40.3	56.2	59
Relative Humidity	%	63%	48%	40%	38%	60%	72%	73%
Wet Bulb Temperature	degree F	84.1	86.1	-9.0	3.7	35.1	51.3	54.0
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)								
Electrical Output	kW	224,241	211,499	198,612	198,597	198,563	198,540	198,537
Heat Rate - LHV	Btu/kWh	9,708	9,876	10,051	10,011	9,958	9,943	9,947
Heat Rate - HHV	Btu/kWh	10,756	10,943	11,136	11,092	11,033	11,016	11,022
GTG Heat Input- LHV	MMBtu/hr	2,177	2,089	1,996	1,988	1,977	1,974	1,975
GTG Heat Input- HHV	MMBtu/hr	2,412	2,314	2,212	2,203	2,191	2,187	2,188
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	4,609,275	4,435,073	4,202,745	4,170,138	4,100,385	4,065,450	4,063,407
Exhaust Temperature	degree F	1,161	1,175	1,111	1,123	1,157	1,175	1,178
Steam Turbine Generator Performance								
Electrical Output	kW	242,261	236,093	210,870	212,971	219,203	222,411	222,917
Duct Burner Fuel Consumption								
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet								
Ar	%	0.86%	0.86%	0.89%	0.89%	0.89%	0.88%	0.88%
CO2	%	3.96%	3.95%	4.04%	4.05%	4.09%	4.11%	4.11%
H2O	%	11.04%	11.04%	7.68%	7.74%	8.25%	8.88%	9.01%
N2	%	72.40%	72.39%	75.07%	75.04%	74.67%	74.19%	74.09%
O2	%	11.74%	11.76%	12.31%	12.27%	12.10%	11.93%	11.90%
Stack Emissions at Exit								
NOx Emissions								
NOx,@15% O2 Into SCR	ppmvd	15.0	15.0	15.0	15.0	15.0	15.0	15.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	131.2	125.9	120.3	119.8	119.1	118.9	119.0
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	17.5	16.8	16.0	16.0	15.9	15.9	15.9
SCR NOx Removal Efficiency	%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%
NH3 Emissions								
NH3 Reacted with NOx (per HRSG)	lb/hr	54.7	52.5	50.2	50.0	49.7	49.6	49.6
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	16.2	15.5	14.8	14.8	14.7	14.7	14.7

Case #		Case 8	Case 9	Case 19	Case 20	Case 21	Case 22	Case 23
Case Description		Unfired 2x100% 95.7°F Evap OFF NG	Unfired 2x100% 104.7°F Evap OFF NG	Unfired 2x75% -7.6°F Evap OFF NG	Unfired 2x75% 6.5°F Evap OFF NG	Unfired 2x75% 40.3°F Evap OFF NG	Unfired 2x75% 56.2°F Evap OFF NG	Unfired 2x75% 59°F Evap OFF NG
CO Emissions								
CO into catalyst	ppmvd	5.2	5.2	5.1	5.1	5.2	5.3	5.3
CO into catalyst, @ 15% O2	ppmvd	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO into catalyst (per HRSG)	lb/hr	21.3	20.4	19.5	19.4	19.3	19.3	19.3
CO out of catalyst	ppmvd	2.61	2.60	2.56	2.57	2.61	2.64	2.64
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	10.6	10.2	9.8	9.7	9.7	9.7	9.7
CO Catalyst Removal Efficiency	%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
SO2 Emissions								
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.237	0.237	0.246	0.246	0.244	0.243	0.242
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.266	0.266	0.266	0.266	0.266	0.266	0.266
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	3.2	3.1	3.0	3.0	2.9	2.9	2.9
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134
Volatile Organic Compounds								
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	3.0	2.9	2.8	2.8	2.8	2.8	2.8
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	12.6	12.1	11.7	11.6	11.4	11.4	11.4
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	14.8	14.2	13.7	13.6	13.4	13.3	13.3
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00614	0.00614	0.00618	0.00617	0.00611	0.00607	0.00607
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	11.4	10.9	10.5	10.4	10.3	10.2	10.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	13.5	13.0	12.5	12.4	12.2	12.1	12.1
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00561	0.00561	0.00565	0.00564	0.00558	0.00554	0.00554
H2SO4 Emissions								
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	4.96	4.76	4.55	4.53	4.51	4.50	4.50
H2SO4 in Exhaust Gas	lb/MMBtu	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206
GHG Emissions								
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	282,150	270,724	258,720	257,671	256,264	255,849	255,967
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	816.9	821.5	850.9	844.6	831.6	826.0	825.7
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	132.9	127.6	121.9	121.4	120.7	120.5	120.6
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	158.5	152.0	145.3	144.7	143.9	143.7	143.8
GHG in Exhaust Gas (per HRSG)	lb/hr	282,441	271,003	258,987	257,938	256,528	256,114	256,232
Stack Exit								
Temperature	degree F	181	179	170	168	166	168	167
Flow Rate (per HRSG)	lb/hr	4,609,275	4,435,073	4,202,745	4,170,138	4,100,385	4,065,450	4,063,407
Flow Rate (per HRSG)	scfm	942,205	906,612	847,813	841,390	828,831	823,720	823,709
Flow Rate (per HRSG)	acfm	1,196,772	1,148,623	1,058,709	1,047,812	1,028,872	1,024,496	1,024,103
Stack Velocity	ft/sec	59.0	56.6	52.2	51.6	50.7	50.5	50.5
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8

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Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 24	Case 25	Case 26	Case 27	Case 28	Case 29	Case 30	Case 31	Case 32
Case Description		Unfired 2x75% 71.9°F Evap OFF NG	Unfired 2x75% 86.6°F Evap OFF NG	Unfired 2x75% 95.7°F Evap OFF NG	Unfired 2x75% 104.7°F Evap OFF NG	Unfired 2x36.1% - 7.6°F Evap OFF NG	Unfired 2x36.2% 6.5°F Evap OFF NG	Unfired 2x32% 40.3°F Evap OFF NG	Unfired 2x32% 56.2°F Evap OFF NG	Unfired 2x32% 59°F Evap OFF NG
Ambient Temperature		71.9 F	86.6 F	95.7 F	104.7 F	-7.6 F	6.5 F	40.3 F	56.2 F	59 F
Gas Turbine Load		75%	75%	75%	75%	36%	36%	32%	32%	32%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2	2	2
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Ambient Conditions										
Temperature	degree F	71.9	86.6	95.7	104.7	-7.6	6.5	40.3	56.2	59
Relative Humidity	%	60%	76%	63%	48%	40%	38%	60%	72%	73%
Wet Bulb Temperature	degree F	62.5	80.0	84.1	86.1	-9.0	3.7	35.1	51.3	54.0
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)										
Electrical Output	kW	190,414	178,133	167,563	157,998	96,000	96,000	85,000	85,000	85,000
Heat Rate - LHV	Btu/kWh	10,090	10,322	10,541	10,767	13,553	13,466	14,116	14,051	14,067
Heat Rate - HHV	Btu/kWh	11,180	11,437	11,680	11,930	15,016	14,920	15,640	15,568	15,586
GTG Heat Input- LHV	MMBtu/hr	1,921	1,839	1,766	1,701	1,301	1,293	1,200	1,194	1,196
GTG Heat Input- HHV	MMBtu/hr	2,129	2,037	1,957	1,885	1,442	1,432	1,329	1,323	1,325
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	0	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	3,963,319	3,862,014	3,783,528	3,710,824	3,103,026	3,073,378	2,873,456	2,842,379	2,840,301
Exhaust Temperature	degree F	1,193	1,198	1,198	1,198	1,111	1,123	1,157	1,175	1,178
Steam Turbine Generator Performance										
Electrical Output	kW	220,309	213,784	208,493	203,125	155,794	157,126	153,193	155,792	156,143
Duct Burner Fuel Consumption										
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet										
Ar	%	0.88%	0.86%	0.86%	0.86%	0.90%	0.90%	0.89%	0.89%	0.89%
CO2	%	4.09%	4.00%	3.92%	3.85%	3.57%	3.58%	3.55%	3.57%	3.57%
H2O	%	9.33%	10.79%	10.96%	10.84%	6.80%	6.85%	7.23%	7.85%	7.99%
N2	%	73.83%	72.62%	72.43%	72.47%	75.42%	75.39%	75.07%	74.59%	74.49%
O2	%	11.86%	11.73%	11.83%	11.98%	13.31%	13.28%	13.25%	13.10%	13.06%
Stack Emissions at Exit										
NOx Emissions										
NOx,@15% O2 Into SCR	ppmvd	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	115.8	110.8	106.4	102.5	78.4	77.9	72.3	72.0	72.0
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	15.4	14.8	14.2	13.7	10.5	10.4	9.6	9.6	9.6
SCR NOx Removal Efficiency	%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%	86.7%
NH3 Emissions										
NH3 Reacted with NOx (per HRSG)	lb/hr	48.3	46.2	44.4	42.7	32.7	32.5	30.1	30.0	30.0
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	14.3	13.7	13.1	12.6	9.7	9.6	8.9	8.9	8.9

Case #		Case 24	Case 25	Case 26	Case 27	Case 28	Case 29	Case 30	Case 31	Case 32
Case Description		Unfired 2x75% 71.9°F Evap OFF NG	Unfired 2x75% 86.6°F Evap OFF NG	Unfired 2x75% 95.7°F Evap OFF NG	Unfired 2x75% 104.7°F Evap OFF NG	Unfired 2x36.1% 7.6°F Evap OFF NG	Unfired 2x36.2% 6.5°F Evap OFF NG	Unfired 2x32% 40.3°F Evap OFF NG	Unfired 2x32% 56.2°F Evap OFF NG	Unfired 2x32% 59°F Evap OFF NG
CO Emissions										
CO into catalyst	ppmvd	5.3	5.2	5.1	5.1	10.1	10.1	10.1	10.2	10.2
CO into catalyst, @ 15% O2	ppmvd	4.0	4.0	4.0	4.0	9.0	9.0	9.0	9.0	9.0
CO into catalyst (per HRSG)	lb/hr	18.8	18.0	17.3	16.6	28.6	28.5	26.4	26.3	26.3
CO out of catalyst	ppmvd	2.64	2.62	2.57	2.53	2.24	2.25	2.24	2.26	2.27
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	9.4	9.0	8.6	8.3	6.4	6.3	5.9	5.8	5.8
CO Catalyst Removal Efficiency	%	50.0%	50.0%	50.0%	50.0%	77.8%	77.8%	77.8%	77.8%	77.8%
SO2 Emissions										
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.241	0.237	0.237	0.237	0.248	0.248	0.247	0.245	0.245
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.266	0.266	0.266	0.266	0.266	0.266	0.266	0.266	0.266
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	2.9	2.7	2.6	2.5	1.9	1.9	1.8	1.8	1.8
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134	0.00134
Volatile Organic Compounds										
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	2.7	2.6	2.5	2.4	1.8	1.8	1.7	1.7	1.7
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	11.0	10.6	10.3	10.0	8.2	8.1	7.5	7.5	7.5
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	12.9	12.4	12.1	11.8	9.7	9.6	8.9	8.8	8.8
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00606	0.00611	0.00618	0.00625	0.00670	0.00668	0.00670	0.00666	0.00665
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	9.9	9.6	9.3	9.0	8.1	8.0	7.5	7.4	7.4
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	11.8	11.4	11.1	10.8	9.6	9.5	8.8	8.7	8.7
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00553	0.00558	0.00565	0.00572	0.00664	0.00662	0.00664	0.00660	0.00660
H2SO4 Emissions										
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	4.38	4.19	4.03	3.88	2.97	2.95	2.74	2.72	2.73
H2SO4 in Exhaust Gas	lb/MMBtu	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206	0.00206
GHG Emissions										
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	249,024	238,316	228,934	220,484	168,631	167,552	155,508	154,790	154,976
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	828.5	836.1	842.3	849.5	969.7	959.8	962.3	950.2	950.4
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	117.3	112.3	107.9	103.9	79.5	78.9	73.3	72.9	73.0
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	139.9	133.8	128.6	123.8	94.7	94.1	87.3	86.9	87.0
GHG in Exhaust Gas (per HRSG)	lb/hr	249,281	238,562	229,171	220,712	168,805	167,725	155,668	154,950	155,136
Stack Exit										
Temperature	degree F	169	170	170	170	170	168	166	165	165
Flow Rate (per HRSG)	lb/hr	3,963,319	3,862,014	3,783,528	3,710,824	3,103,026	3,073,378	2,873,456	2,842,379	2,840,301
Flow Rate (per HRSG)	scfm	804,464	788,578	773,270	758,246	624,772	618,908	579,542	574,628	574,498
Flow Rate (per HRSG)	acfm	1,002,495	984,662	965,416	947,280	780,251	770,694	718,685	711,267	711,962
Stack Velocity	ft/sec	49.4	48.5	47.6	46.7	38.5	38.0	35.4	35.1	35.1
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8

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Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 33	Case 34	Case 35	Case 36	Case 202	Case 203	Case 204	Case 205	Case 206
Case Description		Unfired 2x33.4% 71.9°F Evap OFF NG	Unfired 2x35.7% 86.6°F Evap OFF NG	Unfired 2x37.9% 95.7°F Evap OFF NG	Unfired 2x40.2% 104.7°F Evap OFF NG	Unfired 2x100% -7.6°F Evap OFF FO With H2O	Unfired 2x100% 40.3°F Evap OFF FO With H2O	Unfired 2x100% 56.2°F Evap OFF FO With H2O	Unfired 2x100% 59°F Evap OFF FO With H2O	Unfired 2x100% 71.9°F Evap OFF FO With H2O
Ambient Temperature		71.9 F	86.6 F	95.7 F	104.7 F	-7.6 F	40.3 F	56.2 F	59 F	71.9 F
Gas Turbine Load		33%	36%	38%	40%	100%	100%	100%	100%	100%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2	2	2
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Ambient Conditions										
Temperature	degree F	71.9	86.6	95.7	104.7	-7.6	40.3	56.2	59	71.9
Relative Humidity	%	60%	76%	63%	48%	40%	38%	72%	73%	60%
Wet Bulb Temperature	degree F	62.5	80.0	84.1	86.1	-9.0	31.4	51.3	54.0	62.5
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)										
Electrical Output	kW	85,000	85,000	85,000	85,000	232,042	249,675	243,533	241,145	231,268
Heat Rate - LHV	Btu/kWh	14,022	13,977	13,940	13,917	10,288	9,684	9,794	9,812	9,962
Heat Rate - HHV	Btu/kWh	15,536	15,486	15,445	15,420	11,048	10,400	10,518	10,537	10,699
GTG Heat Input- LHV	MMBtu/hr	1,192	1,188	1,185	1,183	2,387	2,418	2,385	2,366	2,304
GTG Heat Input- HHV	MMBtu/hr	1,321	1,316	1,313	1,311	2,564	2,597	2,562	2,541	2,474
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	71,133	70,434	71,139	70,571	77,808
Exhaust Flow (per HRSG)	lb/hr	2,815,863	2,821,125	2,837,130	2,853,431	5,221,492	5,302,103	5,289,495	5,260,890	5,092,453
Exhaust Temperature	degree F	1,193	1,198	1,198	1,198	1,026	1,025	1,030	1,031	1,043
Steam Turbine Generator Performance										
Electrical Output	kW	155,718	154,445	154,422	154,008	220,753	224,112	226,008	225,375	222,589
Duct Burner Fuel Consumption										
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet										
Ar	%	0.88%	0.87%	0.87%	0.87%	0.87%	0.86%	0.86%	0.86%	0.85%
CO2	%	3.59%	3.55%	3.51%	3.49%	5.00%	4.98%	4.91%	4.90%	4.92%
H2O	%	8.37%	9.94%	10.20%	10.17%	7.12%	7.32%	8.03%	8.13%	8.77%
N2	%	74.20%	72.95%	72.72%	72.72%	72.75%	72.59%	72.03%	71.96%	71.46%
O2	%	12.96%	12.70%	12.70%	12.75%	14.26%	14.24%	14.16%	14.15%	14.00%
Stack Emissions at Exit										
NOx Emissions										
NOx,@15% O2 Into SCR	ppmvd	15.0	15.0	15.0	15.0	25.0	25.0	25.0	25.0	25.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	71.8	71.6	71.4	71.3	253.7	257.1	253.6	251.5	245.4
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	4.5	4.5	4.5	4.5	4.5
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	9.6	9.5	9.5	9.5	45.7	46.3	45.6	45.3	44.2
SCR NOx Removal Efficiency	%	86.7%	86.7%	86.7%	86.7%	82.0%	82.0%	82.0%	82.0%	82.0%
NH3 Emissions										
NH3 Reacted with NOx (per HRSG)	lb/hr	29.9	29.9	29.8	29.7	100.1	101.4	100.1	99.3	96.8
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	8.9	8.8	8.8	8.8	18.8	19.0	18.8	18.6	18.2

Case #		Case 33	Case 34	Case 35	Case 36	Case 202	Case 203	Case 204	Case 205	Case 206
Case Description		Unfired 2x33.4% 71.9°F Evap OFF NG	Unfired 2x35.7% 86.6°F Evap OFF NG	Unfired 2x37.9% 95.7°F Evap OFF NG	Unfired 2x40.2% 104.7°F Evap OFF NG	Unfired 2x100% - 7.6°F Evap OFF FO With H2O	Unfired 2x100% 40.3°F Evap OFF FO With H2O	Unfired 2x100% 56.2°F Evap OFF FO With H2O	Unfired 2x100% 59°F Evap OFF FO With H2O	Unfired 2x100% 71.9°F Evap OFF FO With H2O
CO Emissions										
CO into catalyst	ppmvd	10.3	10.4	10.3	10.2	5.1	5.1	5.0	5.0	5.1
CO into catalyst, @ 15% O2	ppmvd	9.0	9.0	9.0	9.0	4.0	4.0	4.0	4.0	4.0
CO into catalyst (per HRSG)	lb/hr	26.2	26.1	26.1	26.0	24.7	25.0	24.7	24.5	23.9
CO out of catalyst	ppmvd	2.29	2.30	2.29	2.27	2.53	2.53	2.51	2.50	2.54
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	5.8	5.8	5.8	5.8	12.4	12.5	12.3	12.2	11.9
CO Catalyst Removal Efficiency	%	77.8%	77.8%	77.8%	77.8%	50.0%	50.0%	50.0%	50.0%	50.0%
SO2 Emissions										
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.244	0.240	0.239	0.239	0.264	0.263	0.261	0.262	0.258
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.266	0.266	0.266	0.266	0.284	0.284	0.284	0.284	0.283
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	1.8	1.8	1.8	1.8	3.9	3.9	3.9	3.9	3.8
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00134	0.00134	0.00134	0.00134	0.00152	0.00152	0.00152	0.00152	0.00152
Volatile Organic Compounds										
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	1.7	1.7	1.7	1.7	3.5	3.6	3.5	3.5	3.4
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	7.4	7.4	7.4	7.4	23.2	23.5	23.3	23.2	22.4
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	8.7	8.7	8.7	8.7	28.2	28.6	28.4	28.2	27.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00660	0.00660	0.00664	0.00666	0.01101	0.01101	0.01108	0.01111	0.01098
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	7.3	7.3	7.3	7.3	21.7	22.0	21.8	21.7	20.9
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	8.6	8.6	8.6	8.7	26.7	27.0	26.8	26.7	25.7
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00654	0.00655	0.00658	0.00660	0.01042	0.01041	0.01048	0.01051	0.01038
H2SO4 Emissions										
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	2.72	2.71	2.70	2.70	5.95	6.03	5.95	5.90	5.74
H2SO4 in Exhaust Gas	lb/MMBtu	0.00206	0.00206	0.00206	0.00206	0.00232	0.00232	0.00232	0.00232	0.00232
GHG Emissions										
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	163.05	163.05	163.05	163.05	163.05
CO2 in Exhaust Gas (per HRSG)	lb/hr	154,473	153,976	153,572	153,322	418,006	423,391	417,666	414,306	403,435
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	948.5	949.2	946.7	946.4	1,220.7	1,170.5	1,171.5	1,170.9	1,177.7
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	72.8	72.5	72.4	72.2	141.3	143.1	141.2	140.0	136.4
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	86.8	86.5	86.3	86.1	168.4	170.6	168.3	166.9	162.6
GHG in Exhaust Gas (per HRSG)	lb/hr	154,632	154,135	153,731	153,480	418,315	423,704	417,975	414,613	403,734
Stack Exit										
Temperature	degree F	167	172	173	175	187	191	194	194	196
Flow Rate (per HRSG)	lb/hr	2,815,863	2,821,125	2,837,130	2,853,431	5,221,492	5,302,103	5,289,495	5,260,890	5,092,453
Flow Rate (per HRSG)	scfm	570,367	574,985	578,899	582,202	1,043,980	1,062,107	1,061,699	1,055,539	1,026,669
Flow Rate (per HRSG)	acfm	709,249	719,795	726,258	732,696	1,339,389	1,370,265	1,376,637	1,367,769	1,335,755
Stack Velocity	ft/sec	35.0	35.5	35.8	36.1	66.0	67.5	67.8	67.4	65.8
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8

BURNS McDONNELL

Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 207	Case 208	Case 209	Case 210	Case 211	Case 212	Case 213	Case 214	Case 215
Case Description		Unfired 2x100% 86.6°F Evap OFF FO With H2O	Unfired 2x100% 104.7°F Evap OFF FO With H2O	Unfired 2x75% -7.6°F Evap OFF FO With H2O	Unfired 2x75% 40.3°F Evap OFF FO With H2O	Unfired 2x75% 56.2°F Evap OFF FO With H2O	Unfired 2x75% 59°F Evap OFF FO With H2O	Unfired 2x75% 71.9°F Evap OFF FO With H2O	Unfired 2x75% 86.6°F Evap OFF FO With H2O	Unfired 2x75% 104.7°F Evap OFF FO With H2O
Ambient Temperature		86.6 F	104.7 F	-7.6 F	40.3 F	56.2 F	59 F	71.9 F	86.6 F	104.7 F
Gas Turbine Load		100%	100%	75%	75%	75%	75%	75%	75%	75%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2	2	2
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Ambient Conditions										
Temperature	degree F	86.6	104.7	-7.6	40.3	56.2	59	71.9	86.6	104.7
Relative Humidity	%	76%	63%	40%	38%	72%	73%	60%	76%	63%
Wet Bulb Temperature	degree F	80.0	92.1	-9.0	31.4	51.3	54.0	62.5	80.0	92.1
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)										
Electrical Output	kW	216,944	192,904	173,413	186,654	182,041	180,248	172,833	162,076	144,008
Heat Rate - LHV	Btu/kWh	10,198	10,583	11,010	10,354	10,436	10,469	10,671	10,973	11,511
Heat Rate - HHV	Btu/kWh	10,951	11,365	11,824	11,119	11,207	11,242	11,460	11,784	12,362
GTG Heat Input- LHV	MMBtu/hr	2,212	2,041	1,909	1,933	1,900	1,887	1,844	1,779	1,658
GTG Heat Input- HHV	MMBtu/hr	2,376	2,192	2,050	2,075	2,040	2,026	1,981	1,910	1,780
Water / Sprint Injection Rate (per HRSG)	lb/hr	84,295	79,980	36,537	36,029	36,387	36,144	39,999	43,533	41,595
Exhaust Flow (per HRSG)	lb/hr	4,874,340	4,525,262	4,172,153	4,279,071	4,207,227	4,189,236	4,083,696	3,949,064	3,748,091
Exhaust Temperature	degree F	1,060	1,087	1,087	1,075	1,089	1,091	1,105	1,120	1,140
Steam Turbine Generator Performance										
Electrical Output	kW	218,154	210,913	198,857	200,422	202,014	201,867	200,245	196,195	188,649
Duct Burner Fuel Consumption										
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet										
Ar	%	0.83%	0.82%	0.87%	0.87%	0.86%	0.86%	0.86%	0.84%	0.83%
CO2	%	4.90%	4.84%	5.02%	4.95%	4.93%	4.92%	4.92%	4.88%	4.76%
H2O	%	10.62%	11.98%	6.39%	6.54%	7.32%	7.42%	7.95%	9.67%	10.96%
N2	%	70.02%	68.95%	73.32%	73.20%	72.59%	72.51%	72.10%	70.75%	69.74%
O2	%	13.64%	13.41%	14.40%	14.44%	14.29%	14.28%	14.17%	13.86%	13.70%
Stack Emissions at Exit										
NOx Emissions										
NOx,@15% O2 Into SCR	ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	236.1	218.6	202.7	205.2	201.7	200.4	196.2	189.6	177.3
NOx,@15% O2 Out of SCR	ppmvd	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	42.5	39.3	36.5	36.9	36.3	36.1	35.3	34.1	31.9
SCR NOx Removal Efficiency	%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%
NH3 Emissions										
NH3 Reacted with NOx (per HRSG)	lb/hr	93.2	86.3	80.0	81.0	79.6	79.1	77.4	74.8	70.0
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	17.5	16.2	15.0	15.2	14.9	14.8	14.5	14.0	13.1

Case #		Case 207	Case 208	Case 209	Case 210	Case 211	Case 212	Case 213	Case 214	Case 215
Case Description		Unfired 2x100% 86.6°F Evap OFF FO With H2O	Unfired 2x100% 104.7°F Evap OFF FO With H2O	Unfired 2x75% -7.6°F Evap OFF FO With H2O	Unfired 2x75% 40.3°F Evap OFF FO With H2O	Unfired 2x75% 56.2°F Evap OFF FO With H2O	Unfired 2x75% 59°F Evap OFF FO With H2O	Unfired 2x75% 71.9°F Evap OFF FO With H2O	Unfired 2x75% 86.6°F Evap OFF FO With H2O	Unfired 2x75% 104.7°F Evap OFF FO With H2O
CO Emissions										
CO into catalyst	ppmvd	5.2	5.1	11.3	11.2	11.2	11.2	11.4	11.4	11.3
CO into catalyst, @ 15% O2	ppmvd	4.0	4.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CO into catalyst (per HRSG)	lb/hr	23.0	21.3	44.4	45.0	44.2	43.9	43.0	41.6	38.9
CO out of catalyst	ppmvd	2.58	2.57	2.52	2.49	2.50	2.49	2.52	2.54	2.50
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	11.5	10.6	9.9	10.0	9.8	9.8	9.6	9.2	8.6
CO Catalyst Removal Efficiency	%	50.0%	50.0%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%
SO2 Emissions										
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.254	0.253	0.267	0.265	0.264	0.264	0.260	0.257	0.256
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.283	0.282	0.284	0.284	0.284	0.284	0.284	0.283	0.282
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	3.6	3.3	3.1	3.1	3.1	3.1	3.0	2.9	2.7
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152
Volatile Organic Compounds										
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	3.3	3.0	2.8	2.9	2.8	2.8	2.7	2.6	2.5
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	21.3	19.7	18.6	19.0	18.6	18.5	18.0	17.3	16.3
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	25.9	24.0	22.7	23.1	22.7	22.6	21.9	21.0	19.9
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01090	0.01093	0.01105	0.01114	0.01111	0.01114	0.01105	0.01102	0.01116
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	19.9	18.4	18.5	18.9	18.5	18.4	17.9	17.2	16.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	24.5	22.7	22.5	23.0	22.5	22.4	21.7	20.9	19.8
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01030	0.01033	0.01098	0.01107	0.01104	0.01107	0.01098	0.01095	0.01110
H2SO4 Emissions										
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	5.52	5.09	4.76	4.82	4.74	4.70	4.60	4.43	4.13
H2SO4 in Exhaust Gas	lb/MMBtu	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232
GHG Emissions										
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05
CO2 in Exhaust Gas (per HRSG)	lb/hr	387,377	357,455	334,332	338,392	332,643	330,407	322,933	311,422	290,261
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,188.2	1,198.1	1,225.4	1,179.6	1,175.2	1,175.1	1,183.1	1,197.0	1,217.9
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	130.9	120.8	113.0	114.4	112.4	111.7	109.2	105.3	98.1
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	156.1	144.0	134.7	136.3	134.0	133.1	130.1	125.5	117.0
GHG in Exhaust Gas (per HRSG)	lb/hr	387,664	357,720	334,579	338,643	332,889	330,652	323,172	311,653	290,477
Stack Exit										
Temperature	degree F	197	195	178	180	183	183	186	188	188
Flow Rate (per HRSG)	lb/hr	4,874,340	4,525,262	4,172,153	4,279,071	4,207,227	4,189,236	4,083,696	3,949,064	3,748,091
Flow Rate (per HRSG)	scfm	986,378	916,918	831,733	854,687	842,055	838,127	820,639	796,217	756,553
Flow Rate (per HRSG)	acfm	1,284,908	1,191,181	1,051,251	1,084,012	1,073,020	1,067,457	1,051,326	1,022,919	971,283
Stack Velocity	ft/sec	63.3	58.7	51.8	53.4	52.9	52.6	51.8	50.4	47.9
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8

BURNS McDONNELL

Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 216	Case 217	Case 218	Case 219	Case 220	Case 221	Case 222	Case 244	Case 245
Case Description		Unfired 2x49.4% -7.6°F Evap OFF FO With H2O	Unfired 2x49.5% 40.3°F Evap OFF FO With H2O	Unfired 2x49.4% 56.2°F Evap OFF FO With H2O	Unfired 2x49.4% 59°F Evap OFF FO With H2O	Unfired 2x49.4% 71.9°F Evap OFF FO With H2O	Unfired 2x49.3% 86.6°F Evap OFF FO With H2O	Unfired 2x49.2% 104.7°F Evap OFF FO With H2O	2x100% 59°F FO w/Evap Cooler	2x100% 71.9°F FO w/Evap Cooler
Ambient Temperature		-7.6 F	40.3 F	56.2 F	59 F	71.9 F	86.6 F	104.7 F	59 F	71.9 F
Gas Turbine Load		49%	50%	49%	49%	49%	49%	49%	100%	100%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF	COOLING ON	COOLING ON
Water Injection		INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2	2	2	2
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Ambient Conditions										
Temperature	degree F	-7.6	40.3	56.2	59	71.9	86.6	104.7	59	71.9
Relative Humidity	%	40%	38%	72%	73%	60%	76%	63%	40%	60%
Wet Bulb Temperature	degree F	-9.0	31.4	51.3	54.0	62.5	80.0	92.1	47.1	62.5
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)										
Electrical Output	kW	114,638	123,514	120,421	119,220	114,250	107,042	94,947	245,775	235,743
Heat Rate - LHV	Btu/kWh	12,970	12,079	12,184	12,228	12,464	12,832	13,538	9,762	9,900
Heat Rate - HHV	Btu/kWh	13,928	12,972	13,085	13,132	13,385	13,780	14,538	10,484	10,632
GTG Heat Input- LHV	MMBtu/hr	1,487	1,492	1,467	1,458	1,424	1,374	1,285	2,399	2,334
GTG Heat Input- HHV	MMBtu/hr	1,597	1,602	1,576	1,566	1,529	1,475	1,380	2,577	2,506
Water / Sprint Injection Rate (per HRSG)	lb/hr	12,575	12,128	12,421	12,342	13,650	14,853	14,151	71,186	75,328
Exhaust Flow (per HRSG)	lb/hr	3,542,249	3,613,573	3,552,742	3,538,019	3,449,988	3,338,544	3,172,719	5,293,477	5,147,403
Exhaust Temperature	degree F	1,087	1,075	1,089	1,091	1,105	1,120	1,140	1,029	1,040
Steam Turbine Generator Performance										
Electrical Output	kW	169,613	169,909	171,430	171,309	169,337	165,127	158,489	225,726	223,211
Duct Burner Fuel Consumption										
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet										
Ar	%	0.88%	0.88%	0.88%	0.87%	0.87%	0.86%	0.84%	0.88%	0.87%
CO2	%	4.63%	4.55%	4.54%	4.53%	4.53%	4.48%	4.39%	5.08%	5.07%
H2O	%	5.19%	5.36%	6.14%	6.25%	6.67%	8.32%	9.63%	8.06%	9.13%
N2	%	74.24%	74.11%	73.50%	73.41%	73.08%	71.79%	70.76%	73.63%	72.80%
O2	%	15.06%	15.10%	14.95%	14.94%	14.85%	14.55%	14.37%	12.35%	12.14%
Stack Emissions at Exit										
NOx Emissions										
NOx,@15% O2 Into SCR	ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	156.9	157.4	154.8	153.8	150.6	145.5	136.6	255.1	248.4
NOx,@15% O2 Out of SCR	ppmvd	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	28.2	28.3	27.9	27.7	27.1	26.2	24.6	45.9	44.7
SCR NOx Removal Efficiency	%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%	82.0%
NH3 Emissions										
NH3 Reacted with NOx (per HRSG)	lb/hr	61.9	62.1	61.1	60.7	59.4	57.4	53.9	100.7	98.0
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	11.6	11.7	11.5	11.4	11.1	10.8	10.1	18.9	18.4

Case #		Case 216	Case 217	Case 218	Case 219	Case 220	Case 221	Case 222	Case 244	Case 245
Case Description		Unfired 2x49.4% -7.6°F Evap OFF FO With H_2O	Unfired 2x49.5% 40.3°F Evap OFF FO With H_2O	Unfired 2x49.4% 56.2°F Evap OFF FO With H_2O	Unfired 2x49.4% 59°F Evap OFF FO With H_2O	Unfired 2x49.4% 71.9°F Evap OFF FO With H_2O	Unfired 2x49.3% 86.6°F Evap OFF FO With H_2O	Unfired 2x49.2% 104.7°F Evap OFF FO With H_2O	2x100% 59°F FO w/Evap Cooler	2x100% 71.9°F FO w/Evap Cooler
CO Emissions										
CO into catalyst	ppmvd	10.2	10.1	10.1	10.1	10.2	10.2	10.1	5.1	5.1
CO into catalyst, @ 15% O_2	ppmvd	9.0	9.0	9.0	9.0	9.0	9.0	9.0	4.0	4.0
CO into catalyst (per HRSG)	lb/hr	34.4	34.5	33.9	33.7	33.0	31.9	29.9	24.8	24.2
CO out of catalyst	ppmvd	2.27	2.24	2.25	2.24	2.27	2.28	2.25	2.53	2.55
CO out of catalyst, @ 15% O_2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	7.6	7.7	7.5	7.5	7.3	7.1	6.7	12.4	12.1
CO Catalyst Removal Efficiency	%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	50.0%	50.0%
SO_2 Emissions										
SO_2 in Exh. Gas @ 15% O_2 (assuming no conversion)	ppmvw	0.272	0.270	0.269	0.269	0.266	0.263	0.261	0.261	0.258
SO_2 in Exh. Gas @ 15% O_2 (assuming no conversion)	ppmvd	0.286	0.286	0.286	0.286	0.285	0.285	0.284	0.284	0.284
SO_2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	2.4	2.4	2.4	2.4	2.3	2.2	2.1	3.9	3.8
SO_2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152
Volatile Organic Compounds										
VOC @ 15% O_2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH_4 (per HRSG)	lb/hr	2.2	2.2	2.2	2.1	2.1	2.0	1.9	3.6	3.5
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Particulates										
PM10, front including $(NH_4)_2SO_4$ (per HRSG)	lb/hr	15.5	15.8	15.4	15.4	14.9	14.4	13.6	23.4	22.6
PM10, front & back including $(NH_4)_2SO_4$ (per HRSG)	lb/hr	19.0	19.3	18.9	18.8	18.2	17.6	16.6	28.4	27.5
PM10, front & back including $(NH_4)_2SO_4$ (per HRSG)	lb/MMBtu	0.01189	0.01202	0.01199	0.01201	0.01193	0.01191	0.01204	0.01102	0.01096
Particulates										
PM10, front including $(NH_4)_2SO_4$ (per HRSG)	lb/hr	15.4	15.6	15.3	15.3	14.8	14.3	13.5	21.8	21.1
PM10, front & back including $(NH_4)_2SO_4$ (per HRSG)	lb/hr	18.9	19.2	18.8	18.7	18.1	17.5	16.5	26.9	26.0
PM10, front & back including $(NH_4)_2SO_4$ (per HRSG)	lb/MMBtu	0.01183	0.01195	0.01192	0.01195	0.01186	0.01185	0.01198	0.01043	0.01036
H_2SO_4 Emissions										
H_2SO_4 in Exhaust Gas (per HRSG)	lb/hr	3.71	3.72	3.66	3.63	3.55	3.42	3.20	5.98	5.82
H_2SO_4 in Exhaust Gas	lb/MMBtu	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232
GHG Emissions										
CO_2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05
CO_2 in Exhaust Gas (per HRSG)	lb/hr	260,345	261,249	256,913	255,267	249,350	240,510	225,067	422,706	413,693
CO_2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,305.3	1,253.2	1,246.3	1,246.0	1,253.5	1,268.5	1,292.1	1,178.6	1,191.0
CH_4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055
CH_4 in Exhaust Gas (per HRSG)	lb/hr	88.0	88.3	86.8	86.3	84.3	81.3	76.1	142.0	138.1
N_2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
N_2O in Exhaust Gas (per HRSG)	lb/hr	104.9	105.3	103.5	102.9	100.5	96.9	90.7	169.3	164.7
GHG in Exhaust Gas (per HRSG)	lb/hr	260,537	261,443	257,104	255,457	249,535	240,688	225,234	423,018	413,996
Stack Exit										
Temperature	degree F	176	178	178	178	182	184	185	193	195
Flow Rate (per HRSG)	lb/hr	3,542,249	3,613,573	3,552,742	3,538,019	3,449,988	3,338,544	3,172,719	5,293,477	5,147,403
Flow Rate (per HRSG)	scfm	703,985	719,619	708,928	705,717	690,957	670,587	637,984	1,063,046	1,038,006
Flow Rate (per HRSG)	acfm	887,729	909,884	896,777	892,316	879,542	856,479	815,021	1,374,941	1,348,287
Stack Velocity	ft/sec	43.8	44.8	44.2	44.0	43.3	42.2	40.2	67.8	66.5
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8

BURNS McDONNELL

Client EKPC
Project Cooper CCGT
2x1 5000F Wet Co

Case #		Case 246	Case 247	Case 248	Case 249	Case 250	Case 251
Case Description		2x100% 86.6°F FO w/Evap Cooler	2x100% 104.7°F FO w/Evap Cooler	2x100% 71.9°F NG w/Evap Cooler	2x100% 86.6°F NG w/Evap Cooler	2x100% 95.7°F NG w/Evap Cooler	2x100% 104.7°F NG w/Evap Cooler
Ambient Temperature		86.6 F	104.7 F	71.9 F	86.6 F	95.7 F	104.7 F
Gas Turbine Load		100%	100%	100%	100%	100%	100%
Evaporative Cooling		COOLING ON	COOLING ON	COOLING ON	COOLING ON	COOLING ON	COOLING ON
Water Injection		INJECTION ON	INJECTION ON	OFF	OFF	OFF	OFF
Duct Firing		N/A	N/A	N/A	N/A	N/A	N/A
Inlet Chiller		N/A	N/A	N/A	N/A	N/A	N/A
No. of Gas Turbines In Operation		2	2	2	2	2	2
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Ambient Conditions							
Temperature	degree F	86.6	104.7	71.9	86.6	95.7	104.7
Relative Humidity	%	76%	63%	40%	76%	63%	48%
Wet Bulb Temperature	degree F	80.0	92.1	57.1	80.0	84.1	86.1
Pressure	psia	14.27	14.27	14.27	14.27	14.27	14.27
Gas Turbine Generator Performance (per GTG)							
Electrical Output	kW	226,736	219,267	259,707	249,395	245,983	240,852
Heat Rate - LHV	Btu/kWh	10,048	10,176	9,360	9,460	9,497	9,552
Heat Rate - HHV	Btu/kWh	10,790	10,928	10,370	10,481	10,522	10,584
GTG Heat Input- LHV	MMBtu/hr	2,278	2,231	2,431	2,359	2,336	2,301
GTG Heat Input- HHV	MMBtu/hr	2,447	2,396	2,693	2,614	2,588	2,549
Water / Sprint Injection Rate (per HRSG)	lb/hr	80,650	83,918	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	4,998,830	4,874,484	5,066,750	4,911,953	4,861,895	4,779,315
Exhaust Temperature	degree F	1,051	1,061	1,132	1,144	1,148	1,155
Steam Turbine Generator Performance							
Electrical Output	kW	219,806	216,673	259,239	253,627	251,787	248,705
Duct Burner Fuel Consumption							
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet							
Ar	%	0.86%	0.85%	0.88%	0.86%	0.86%	0.86%
CO2	%	5.08%	5.09%	4.05%	4.03%	4.02%	4.03%
H2O	%	10.18%	10.98%	9.19%	11.05%	11.51%	11.75%
N2	%	71.98%	71.36%	73.91%	72.44%	72.07%	71.89%
O2	%	11.91%	11.72%	11.96%	11.62%	11.53%	11.47%
Stack Emissions at Exit							
NOx Emissions							
NOx,@15% O2 Into SCR	ppmvd	25.0	25.0	15.0	15.0	15.0	15.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	242.8	238.1	146.5	142.1	140.8	138.6
NOx,@15% O2 Out of SCR	ppmvd	4.5	4.5	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	43.7	42.9	19.5	19.0	18.8	18.5
SCR NOx Removal Efficiency	%	82.0%	82.0%	86.7%	86.7%	86.7%	86.7%
NH3 Emissions							
NH3 Reacted with NOx (per HRSG)	lb/hr	95.8	93.9	61.4	61.4	61.9	62.0
NH3 slip @ 15% O2	ppmvd	5	5	5	5	5	5
NH3 slip (per HRSG)	lb/hr	18.0	17.6	18.1	17.5	17.4	17.1

Case #		Case 246	Case 247	Case 248	Case 249	Case 250	Case 251
Case Description		2x100% 86.6°F FO w/Evap Cooler	2x100% 104.7°F FO w/Evap Cooler	2x100% 71.9°F NG w/Evap Cooler	2x100% 86.6°F NG w/Evap Cooler	2x100% 95.7°F NG w/Evap Cooler	2x100% 104.7°F NG w/Evap Cooler
CO Emissions							
CO into catalyst	ppmvd	5.2	5.2	5.2	5.3	5.3	5.3
CO into catalyst, @ 15% O2	ppmvd	4.0	4.0	4.0	4.0	4.0	4.0
CO into catalyst (per HRSG)	lb/hr	23.7	23.2	23.8	23.1	22.9	22.5
CO out of catalyst	ppmvd	2.59	2.62	2.61	2.65	2.66	2.67
CO out of catalyst, @ 15% O2	ppmvd	2.00	2.00	2.00	2.00	2.00	2.00
CO out of catalyst (per HRSG)	lb/hr	11.8	11.6	11.9	11.5	11.4	11.3
CO Catalyst Removal Efficiency	%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
SO2 Emissions							
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.254	0.252	0.242	0.237	0.236	0.235
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.283	0.283	0.266	0.266	0.266	0.266
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	3.7	3.6	3.6	3.5	3.5	3.4
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00152	0.00152	0.00134	0.00134	0.00134	0.00134
Volatile Organic Compounds							
VOC @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0
VOC as CH4 (per HRSG)	lb/hr	3.4	3.3	3.4	3.3	3.3	3.2
VOC % Removal in Catalyst	%	0%	0%	0%	0%	0%	0%
Particulates							
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	21.9	21.3	14.0	13.6	13.4	13.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	26.6	25.8	16.4	15.9	15.7	15.4
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01085	0.01077	0.00609	0.00607	0.00606	0.00604
Particulates							
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	20.4	19.8	12.6	12.2	12.0	11.8
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	25.1	24.4	15.0	14.5	14.3	14.1
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01026	0.01017	0.00556	0.00554	0.00553	0.00551
H2SO4 Emissions							
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	5.68	5.56	5.54	5.38	5.33	5.24
H2SO4 in Exhaust Gas	lb/MMBtu	0.00232	0.00232	0.00206	0.00206	0.00206	0.00206
GHG Emissions							
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.05	163.05	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	406,257	400,288	452,592	441,890	440,145	436,033
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,206.8	1,221.9	1,162.5	1,174.6	1,183.6	1,193.9
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	0.055	0.055	0.055	0.055	0.055	0.055
CH4 in Exhaust Gas (per HRSG)	lb/hr	134.8	132.1	148.4	144.1	142.7	140.5
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	0.066	0.066	0.066	0.066	0.066	0.066
N2O in Exhaust Gas (per HRSG)	lb/hr	160.7	157.4	176.9	171.7	170.0	167.5
GHG in Exhaust Gas (per HRSG)	lb/hr	406,552	400,577	452,918	442,205	440,457	436,341
Stack Exit							
Temperature	degree F	197	198	184	184	184	184
Flow Rate (per HRSG)	lb/hr	4,998,830	4,874,484	5,066,750	4,911,953	4,861,895	4,779,315
Flow Rate (per HRSG)	scfm	1,012,093	989,918	1,028,013	1,003,887	995,477	979,471
Flow Rate (per HRSG)	acfm	1,318,054	1,291,275	1,311,208	1,280,791	1,269,985	1,249,285
Stack Velocity	ft/sec	65.0	63.6	64.6	63.1	62.6	61.6
Stack Diameter	ft	20.8	20.8	20.8	20.8	20.8	20.8

5. Derivation of Emissions Factors and Calculations for EU 17: NG-Fired Dew Point Heater No. 1

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 17: NG-Fired Dew Point Heater No. 1 are documented in this section.

Emission Unit ID:	17
Emission Unit Name:	NG-Fired Dew Point Heater No. 1
Emission Unit Description:	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)
Equipment ID (SI):	COMB0007

5.1 Process Unit(s)

Process ID:	01
EU ID - PID:	17-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-17
Stack Description:	N/A
Applicable Regulation:	401 KAR 59:015, 401 KAR 60.005 (NSPS Dc)
Construction Date:	2/1/2028
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	39990003
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units:	Million Cubic Feet Natural Gas Burned

5.2 NG-Fired Dew Point Heater No. 1 Operational Data and Specifications for 17-01

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**11.65**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0114	MMscf/hr	
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	

5.3 Derivation and Documentation of Emission Factors for 17-01

5.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm * 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

5.3.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.049	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
CO	00630-08-0	0.082	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Table 1.4-2 + EPA Speciate Database
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000 Ccf/MMscf = 1.427 lb/MMscf
H_2SO_4	7664-93-9	1.03E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

5.3.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

5.4 Potential Emissions Summary for 17-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_x	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.571	2.502
CO	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.960	4.203
VOC	5.50	AP-42 Table 1.4-2	0.063	0.275
$PM/PM_{10}/PM_{2.5}$-Filt	1.90	AP-42 Table 1.4-2	0.022	0.095
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.018	0.079
$PM/PM_{10}/PM_{2.5}$ Total	3.47	AP-42 Table 1.4-2	0.040	0.174
SO_2	1.43	Pipeline spec conversion	0.016	0.071
H_2SO_4	0.109	Pipeline spec conversion	1.25E-03	5.47E-03
Lead	0.0005	AP-42, Table 1.4-2	5.71E-06	2.50E-05
CO_2	120019	40 CFR 98, Table C-1	1,371	6,005
CH_4	2.26	40 CFR 98, Table C-2	0.026	0.113
N_2O	0.226	40 CFR 98, Table C-2	0.003	0.011
CO_2e	120142	40 CFR 98, Subpart A	1,372	6,011
Hazardous Air Pollutants				
Benzene	2.1E-03	AP-42, Table 1.4-3	2.40E-05	1.05E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.37E-05	6.00E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	8.57E-04	3.75E-03
Hexane	1.8E+00	AP-42, Table 1.4-3	2.06E-02	9.01E-02
Naphthalene	6.1E-04	AP-42, Table 1.4-3	6.97E-06	3.05E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	3.88E-05	1.70E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	2.28E-06	1.00E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.26E-05	5.50E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.60E-05	7.00E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	4.34E-06	1.90E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	2.97E-06	1.30E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	2.40E-05	1.05E-04
Total HAP	1.888	Sum of HAPs	0.022	0.094

Sample Calculations:

NOx (lb/hr) = 50.000 lb/MMscf x 0.0114 MMscf/hr = 0.571 lb/hr NOx

NOx (tpy) = 0.571 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.50 tpy NOx

6. Derivation of Emissions Factors and Calculations for EU 20: NG-Fired Auxiliary Boiler

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 20: NG-Fired Auxiliary Boiler are documented in this section.

Emission Unit ID:	20
Emission Unit Name:	NG-Fired Auxiliary Boiler
Emission Unit Description:	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)
Equipment ID (SI):	COMB0010

6.1 Process Unit(s)

Process ID:	01
EU ID - PID:	20-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-20
Stack Description:	TBD
Applicable Regulation:	401 KAR 51:017, 59:015, 60:005, & 63:002, 40 CFR 60 Subpart Dc, 40 CFR 63 Subpart DDDDD
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	10200602
SCC Description:	External Combustion Boilers - Industrial (1-02) - Natural Gas (1-02-006) - 10-100 Million Btu/hr (1-02-006-02)
SCC Units:	Million Cubic Feet Natural Gas Burned

6.2 NG-Fired Auxiliary Boiler Operational Data and Specifications for 20-01

> Although the Aux Boiler will only operate periodically to assist with warm or cold startups of the combustion turbines and to provide freeze protection during winter downtime hours, potential emissions are calculated based on 8,760 hr/yr of operation for simplicity and conservatism.

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**78.32**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0739	MMscf/hr	= 78.32 MMBtu/hr / 1060 Btu/scf
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	

6.3 Derivation and Documentation of Emission Factors for 20-01

6.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Standard Temperature	68	°F	STP Parameters
	528	°R	
Standard Pressure	1	atm	STP Parameters
Universal Gas Constant	0.7302	cf-atm/ (lbmol-°R)	Constant
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm * 0.7302 cf-atm/(lbmol-°R)
Mass Conversion	7,000	gr/lb	
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

6.3.2 Prospective Vendor Data

Pollutant	CAS #	Concentration (ppmv @ 3% O_2)	Concentration (ppmv @ 0% O_2)	Emission Factor Basis
NO_x	na	9	11	EKPC requirement for boiler with Ultra LNB; exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)
CO	00630-08-0	4	5	EKPC requirement at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

6.3.3 Regulated NSR Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.011	11.578	EKPC requirement (Vendor Guarantee) = 11 lbmol NO2/10^6 lbmol air * 46.01 lb NO2/lbmol / 385.5 scf/lbmol * 8,710 dscf/MMBtu * 1,060 MMBtu/MMscf
CO	00630-08-0	0.003	3.133	EKPC requirement (Vendor Guarantee) = 5 lbmol CO/10^6 lbmol air x 28.01 lb CO/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,060 MMBtu/MMscf
VOC	na	0.0054	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Section 1.4 Table 1.4-2 (7/98), difference between EPA Speciate database for total PM and AP-42 for filterable PM.
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	= 0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb S/lbmol * 10,000 Ccf/MMscf
H_2SO_4	7664-93-9	0.0001	0.109	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.262	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

6.3.4 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.89

6.4 Potential Emissions Summary for 20-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	11.58	EKPC requirement (Vendor Guarantee)	0.855	3.75
CO	3.13	EKPC requirement (Vendor Guarantee)	0.231	1.01
VOC	5.50	AP-42 Table 1.4-2	0.406	1.78
$PM/PM_{10}/PM_{2.5}$-Filt	1.90	AP-42 Table 1.4-2	0.140	0.61
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.116	0.51
$PM/PM_{10}/PM_{2.5}$ Total	3.47	AP-42 Table 1.4-2	0.256	1.12
SO_2	1.43	Pipeline spec conversion	0.105	0.46
H_2SO_4	0.109	Pipeline spec conversion	0.008	0.04
Lead	0.0005	AP-42, Table 1.4-2	3.69E-05	1.62E-04
CO_2	120019	40 CFR 98, Table C-1	8,868	38,841
CH_4	2.26	40 CFR 98, Table C-2	0.167	0.73
N_2O	0.226	40 CFR 98, Table C-2	0.017	0.07
CO_2e	120142	40 CFR 98, Subpart A	8,877	38,881
Hazardous Air Pollutants				
Benzene	2.1E-03	AP-42, Table 1.4-3	1.55E-04	6.80E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	8.87E-05	3.88E-04
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	5.54E-03	2.43E-02
Hexane	1.80	AP-42, Table 1.4-3	1.33E-01	0.583
Naphthalene	6.1E-04	AP-42, Table 1.4-3	4.51E-05	1.97E-04
Toluene	3.4E-03	AP-42, Table 1.4-3	2.51E-04	1.10E-03
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.48E-05	6.47E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	8.13E-05	3.56E-04
Chromium	1.4E-03	AP-42, Table 1.4-4	1.03E-04	4.53E-04
Manganese	3.8E-04	AP-42, Table 1.4-4	2.81E-05	1.23E-04
Mercury	2.6E-04	AP-42, Table 1.4-4	1.92E-05	8.41E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	1.55E-04	6.80E-04
Total HAP	1.89	Sum of HAPs	0.139	0.611

Sample Calculations:

NOx (lb/hr) = 11.578 lb/MMscf x 0.0739 MMscf/hr = 0.855 lb/hr NOx

NOx (tpy) = 0.855 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 3.75 tpy NOx

7. Derivation of Emissions Factors and Calculations for EU 23: NG-Fired Dew Point Heater No. 2

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 23: NG-Fired Dew Point Heater No. 2 are documented in this section.

Emission Unit ID:	23
Emission Unit Name:	NG-Fired Dew Point Heater No. 2
Emission Unit Description:	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)
Equipment ID (SI):	COMB0013

7.1 Process Unit(s)

Process ID:	01
EU ID - PID:	23-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-23
Stack Description:	TBD
Applicable Regulation:	401 KAR 59:015, 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code	
SCC:	39990003
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units:	Million Cubic Feet Natural Gas Burned

7.2 NG-Fired Dew Point Heater No. 2 Operational Data and Specifications for 23-01

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**9.13**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0086	MMscf/hr	= 9.13 MMBtu/hr / 1060 Btu/scf
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	

7.3 Derivation and Documentation of Emission Factors for 23-01

7.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	

F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

7.3.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.049	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
CO	00630-08-0	0.082	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Section 1.4 Table 1.4-2 (7/98), difference between EPA Speciate database for total PM and AP-42 for filterable PM.
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	= 0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb S/lbmol * 10,000 Ccf/MMscf
H_2SO_4	7664-93-9	1.03E-04	0.109	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

7.3.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.89

7.4 Potential Emissions Summary for 23-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.431	1.886
CO	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.724	3.169
VOC	5.5	AP-42 Table 1.4-2	0.047	0.207
$PM/PM_{10}/PM_{2.5}$-Filt	1.9	AP-42 Table 1.4-2	0.016	0.072
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.014	0.059
$PM/PM_{10}/PM_{2.5}$ Total	3.47	AP-42 Table 1.4-2	0.030	0.131
SO_2	1.43	Pipeline spec conversion	0.012	0.054
H_2SO_4	0.109	Pipeline spec conversion	9.41E-04	4.12E-03
Lead	0.0005	AP-42, Table 1.4-2	4.31E-06	1.89E-05
CO_2	120019	40 CFR 98, Table C-1	1,034	4,528
CH_4	2.2619	40 CFR 98, Table C-2	0.019	0.085
N_2O	0.2262	40 CFR 98, Table C-2	0.002	0.009
CO_2e	120142	40 CFR 98, Subpart A	1,035	4,532
Hazardous Air Pollutants				
Benzene	2.1E-03	AP-42, Table 1.4-3	1.81E-05	7.92E-05
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.03E-05	4.53E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	6.46E-04	2.83E-03
Hexane	1.80	AP-42, Table 1.4-3	1.55E-02	6.79E-02
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.25E-06	2.30E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	2.93E-05	1.28E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.72E-06	7.55E-06
Cadmium	1.1E-03	AP-42, Table 1.4-4	9.47E-06	4.15E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.21E-05	5.28E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	3.27E-06	1.43E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	2.24E-06	9.81E-06
Nickel	2.1E-03	AP-42, Table 1.4-4	1.81E-05	7.92E-05
Total HAP	1.89	Sum of HAPs	0.016	0.071

Sample Calculations:

NOx (lb/hr) = 50.000 lb/MMscf x 0.0086 MMscf/hr = 0.431 lb/hr NOx

NOx (tpy) = 0.431 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 1.89 tpy NOx

8. Derivation of Emissions Factors and Calculations for EU 24: NG-Fired Dew Point Heater No. 3

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 24: NG-Fired Dew Point Heater No. 3 are documented in this section.

Emission Unit ID:	24
Emission Unit Name:	NG-Fired Dew Point Heater No. 3
Emission Unit Description:	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)
Equipment ID (SI):	COMB0014

8.1 Process Unit(s)

Process ID:	01
EU ID - PID:	24-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-24
Stack Description:	TBD
Applicable Regulation:	401 KAR 59:015, 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes
Source Classification Code	
SCC:	39990003
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units:	Million Cubic Feet Natural Gas Burned

8.2 NG-Fired Dew Point Heater No. 3 Operational Data and Specifications for 24-01

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**9.13**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0086	MMscf/hr	= 9.13 MMBtu/hr / 1060 Btu/scf
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	

8.3 Derivation and Documentation of Emission Factors for 24-01

8.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	

Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

8.3.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.049	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
CO	00630-08-0	0.082	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Section 1.4 Table 1.4-2 (7/98), difference between EPA Speciate database for total PM and AP-42 for filterable PM.
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	= 0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb S/lbmol * 10,000 Ccf/MMscf
H_2SO_4	7664-93-9	1.03E-04	0.109	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4
				= 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF

8.3.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.89

8.4 Potential Emissions Summary for 24-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_x	50	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.431	1.886
CO	84	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	0.724	3.169
VOC	5.5	AP-42 Table 1.4-2	0.047	0.207
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.016	0.072
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.014	0.059
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.030	0.131
SO_2	1.43	Pipeline spec conversion	0.012	0.054
H_2SO_4	0.109	Pipeline spec conversion	9.41E-04	4.12E-03
Lead	0.0005	AP-42, Table 1.4-2	4.31E-06	1.89E-05
CO_2	120019	40 CFR 98, Table C-1	1,034	4,528
CH_4	2.2619	40 CFR 98, Table C-2	0.019	0.085
N_2O	0.2262	40 CFR 98, Table C-2	0.002	0.009
CO_2e	120142	40 CFR 98, Subpart A	1,035	4,532
Hazardous Air Pollutants				
Benzene	2.1E-03	AP-42, Table 1.4-3	1.81E-05	7.92E-05
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.03E-05	4.53E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	6.46E-04	2.83E-03
Hexane	1.80	AP-42, Table 1.4-3	1.55E-02	6.79E-02
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.25E-06	2.30E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	2.93E-05	1.28E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.72E-06	7.55E-06
Cadmium	1.1E-03	AP-42, Table 1.4-4	9.47E-06	4.15E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.21E-05	5.28E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	3.27E-06	1.43E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	2.24E-06	9.81E-06
Nickel	2.1E-03	AP-42, Table 1.4-4	1.81E-05	7.92E-05
Total HAP	1.89	Sum of HAPs	0.016	0.071

Sample Calculations:

NOx (lb/hr) = 50.000 lb/MMscf x 0.0086 MMscf/hr = 0.431 lb/hr NOx

NOx (tpy) = 0.431 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 1.89 tpy NOx

9. Derivation of Emissions Factors and Calculations for EU 25: CCGT Cooling Tower

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 25: CCGT Cooling Tower are documented in this section.

Emission Unit ID:	25
Emission Unit Name:	CCGT Cooling Tower
Emission Unit Description:	One Mechanical Draft Cooling Tower, 9 Cells
Equipment ID (SI):	EQPT0021

9.1 Process Unit(s)

Process ID:	01
EU ID - PID:	25-01
Process Description:	Recirculating Water
Control Device ID:	N/A
Control Device Description:	Inherent drift eliminators
Stack ID:	S-25
Stack Description:	TBD
Applicable Regulation:	401 KAR 59:010, 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	Yes
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	38500101
SCC Description:	Industrial Processes - Cooling Tower (3-85) - Process Cooling (3-85-001) - Mechanical Draft (3-85-001-01)
SCC Units:	Million Gallons Cooling Water Throughput

9.2 CCGT Cooling Tower Operation Data and Specifications for 25-01

> As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. Particulate matter emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of particulate matter.

> Particulate matter emissions from cooling towers are estimated using the procedures of AP-42 Section 13.4 (1/1995 edition), in which PM emissions are estimated as a function of the tower flow capacity, drift loss, and total dissolved solids (TDS) in the cooling tower recirculating water.

Parameter	Value	Units	Basis
Max Annual Operating Hours	8,760	hr/yr	
Circulating Water Flow Rate	165,800	gpm	Design specification
	9.948	MMgal/hr	= 165,800 gpm * 60 min/hr / 10^6 gal/MMgal
Total Dissolved Solids (TDS) of Recirculating Water	2500	ppm	Design specification
Drift Percentage for Cooling Tower Mist Eliminator	0.0005	%	Design specification
Density of Circulating Water	8.34	lb/gal	

9.3 Derivation and Documentation of Emission Factors for 25-01

> PM_{10} and $PM_{2.5}$ emission factors are derived from the PM emission factor calculated above using the methodology presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

> The aerodynamic diameter of a particle resulting from drift was calculated over a target droplet size distribution presented in the table below, taken from the source cited above. By interpolating on the calculated aerodynamic particle diameter, the corresponding mass percentage smaller than $PM_{2.5}$ and PM_{10} can be derived.

9.3.1 Constants and Conversion Factors

Droplet Diameter Size[1] (µm)	EPRI % Mass Smaller[1] (%)	Droplet Volume (µm³)	Droplet Mass (µg)	Particle Mass (Solids) (µg)	Solid Particle Volume (µm³)	Solid Particle Diameter (µm)	Aerodyn. Particle Diameter (µm)
10	0	524	5.24E-04	1.31E-06	0.59	1.04	1.5
16.2	***0.121***	***2,206***	***2.21E-03***	5.52E-06	***2.51***	1.69	***2.5***
20	0.196	4,189	4.19E-03	1.05E-05	4.76	2.09	3.1
30	0.226	14,137	0.01	3.53E-05	16.06	3.13	4.6
40	0.514	33,510	0.03	8.38E-05	38.08	4.17	6.2
50	1.816	65,450	0.07	1.64E-04	74.37	5.22	7.7
60	5.702	113,097	0.11	2.83E-04	128.52	6.26	9.3
64.6	***12.911***	***141,204***	***0.14***	3.53E-04	***160.46***	6.74	***10.0***
70	21.348	179,594	0.18	4.49E-04	204.08	7.30	10.8
90	49.812	381,704	0.38	9.54E-04	433.75	9.39	13.9
110	70.509	696,910	0.70	1.74E-03	792	11.48	17.0
130	82.023	1,150,347	1.15	2.88E-03	1,307	13.57	20.1
150	88.012	1,767,146	1.77	4.42E-03	2,008	15.65	23.2
180	91.032	3,053,628	3.05	7.63E-03	3,470	18.78	27.9
210	92.468	4,849,048	4.85	1.21E-02	5,510	21.91	32.5
240	94.091	7,238,229	7.24	1.81E-02	8,225	25.04	37.1
270	94.689	10,305,995	10.31	2.58E-02	11,711	28.18	41.8
300	96.288	14,137,167	14.14	3.53E-02	16,065	31.31	46.4
350	97.011	22,449,298	22.45	5.61E-02	25,511	36.52	54.2
400	98.340	33,510,322	33.51	8.38E-02	38,080	41.74	61.9
450	99.071	47,712,938	47.71	1.19E-01	54,219	46.96	69.7
500	99.071	65,449,847	65.45	1.64E-01	74,375	52.18	77.4
600	100	113,097,336	113.10	2.83E-01	128,520	62.61	92.9

Bold highlights indicate interpolated values to determine PM_{10} and $PM_{2.5}$ size fractions.

[1] Based on drift droplet size distribution testing from EPRI test facility published in the Reisman and Frisbie paper.

9.3.2 Summary of PM Emission Factors

Estimated PM_{10}/PM Ratio	0.129	EPRI ratio of mass smaller than PM_{10} (based on interpolation in table above)
Estimated $PM_{2.5}$/PM Ratio	0.001	EPRI ratio of mass smaller than $PM_{2.5}$ (based on interpolation in table above)

Pollutant	Emission Factor (lb/MMgal)	Basis
PM	0.1043	= 8.34 lb/gal * 2500 ppm * 0.0005 drift %
PM_{10}	0.0135	= 0.1043 lb PM/MMgal circulating water * 0.129 Estimated PM10/PM Ratio
$PM_{2.5}$	1.257E-04	= 0.1043 lb PM/MMgal circulating water * 1.21E-03 Estimated PM2.5/PM Ratio

9.4 Potential Emissions Summary for 25-01

Pollutant	Emission Factor (lb/MMgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
PM	0.104	2500 ppm TDS in recirculating water and 0.0005% drift	1.037	4.54
PM_{10}	0.013	EPRI PM_{10}/PM ratio	0.134	0.59
$PM_{2.5}$	1.257E-04	EPRI $PM_{2.5}$/PM ratio	1.25E-03	5.48E-03

Sample Calculations:

PM (lb/hr) = 0.104 lb/MMgal * 9.9 MMgal/hr = 1.037 lb/hr PM

PM (tpy) = 1.037 lb/hr * 8,760 hr/yr / 2,000 lb/ton = 4.54 tpy PM

10. Derivation of Emissions Factors and Calculations for EU 21: 1.25 MW Generator/Engine

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 21: 1.25 MW Generator/Engine are documented in this section.

Emission Unit ID:	21
Emission Unit Name:	1.25 MW Generator/Engine
Emission Unit Description:	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)
Equipment ID (SI):	COMB0011

10.1 Process Unit(s)

Process ID:	01
EU ID - PID:	21-01
Process Description:	Diesel Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-21
Stack Description:	TBD
Applicable Regulation:	NSPS IIII, RICE MACT, 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	20100102
SCC Description:	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)
SCC Units:	1000 Gallons Distillate Oil (Diesel) Burned

10.2 1.25 MW Generator/Engine Operational Data and Specifications for 21-01

Generator Rating	1,250	**kW**	Maximum required generator power output
Heat Input	12.5	MMBtu/hr	EKPC requirement
Annual Operating Hours	500	hr/yr	The PTE of emergency generators may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	136.20	MMBtu/Mgal	Average for EKPC Fuel Oil
Diesel HHV used for AP-42 1.4 Emission Factors	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19,300 Btu/lb * 7.1 lb/gallon = 137,030 Btu/gallon
Diesel HHV used for 40 CFR 98, Subpart C Emission Factors	138.00	MMBtu/Mgal	HHV per 40 CFR 98 Subpart C
Avg Brake-Specific Fuel Consumption	7,000	Btu/hp-hr	AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines, Table 3.3-1 Footnote a
Gross Engine Rating	2,200	bhp	EKPC requirement
Maximum Fuel Consumption	0.1131	Mgal/hr	= 2,200 bhp / 136.2 MMBtu/Mgal / 1,000,000 * 7,000 Btu/hp-hr

10.3 Derivation and Documentation of Emission Factors for 21-01

> While the exact make and model of the emergency engine is not known, it is assumed that the engine will be compliant with the Tier 2 emission standards for generator output greater than 560 kW. Emission factors for pollutants without Tier 2 emission standards are from AP-42, Section 3.4 Large Stationary Diesel and All Stationary Dual-Fuel Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO_2 greenhouse gases).

10.3.1 NMHC + NOX

Emission factor for NO_X + NMHC:	6.4	g/kW-hr	Tier 2 Emission Standards per NSPS IIII

> A separate VOC and NO_X emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NO_X factor in AP-42 Table 3.4-1 (10/1996 edition).

Sum of AP-42 NO_X and TOC emission factors:	0.025	lb/hp-hr	AP-42 Table 3.4-1 for Diesel Fuel
Ratio of NO_X factor to sum of NO_X and TOC factors:	0.974		= 0.024 / 0.025 lb/hp-hr
Ratio of TOC factor to sum of NO_X and TOC factors:	0.026		= 0.91 * 7.05 E-04 / 0.025

NO_X

Emission factor for NO_X:	4.65	g/hp-hr	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW
NO_X emission factor in terms of SCC units:	199.39	lb/Mgal	= 4.65 g/hp-hr * 2,200 bhp / 0.113 Mgal/hr / 453.593 g/lb

VOC

Emission factor for VOC:	0.12	g/hp-hr	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW
VOC emission factor in terms of SCC units:	5.330	lb/Mgal	= 0.12 g/hp-hr * 2,200 bhp / 0.113 Mgal/hr / 453.593 g/lb

CO

Emission factor for CO:	2.61	g/hp-hr	Tier 2 Emission Standards per NSPS IIII
CO emission factor in terms of SCC units:	111.955	lb/Mgal	= 2.61 g/hp-hr * 2,200 bhp / 0.113 Mgal/hr / 453.593 g/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.15	g/hp-hr	Tier 2 Emission Standards per NSPS IIII
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	6.397	lb/Mgal	= 0.15 g/hp-hr * 2,200 bhp / 0.113 Mgal/hr / 453.593 g/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF * 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu * 137.03 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A, Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1	
CH_4	28	89 FR 42218, May 14, 2024
N_2O	265	89 FR 42218, May 14, 2024

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,501	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.913	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.183	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.20	22,575	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

10.3.2 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.4-3 and 3.4-4 (10/96 Edition). Emission factors are converted from lb/MMBtu as provided in AP-42 to lb/Mgal as applicable to the SCC designation.

Pollutant	CAS #	HAP?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)
Acetaldehyde	75-07-0	Y	2.52E-05	3.45E-03
Acrolein	107-02-8	Y	7.88E-06	1.08E-03
Benzene	71-43-2	Y	7.76E-04	1.06E-01
Formaldehyde	50-00-0	Y	7.89E-05	1.08E-02
Naphthalene	91-20-3	Y	1.30E-04	1.78E-02
PAH		Y	2.12E-04	2.91E-02
Toluene	108-88-3	Y	2.81E-04	3.85E-02
Xylenes	1330-20-7	Y	1.93E-04	2.64E-02

10.4 Potential Emissions Summary for 21-01

Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	(tpy)
NO_x	199.388	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW	22.545	5.64
CO	111.955	Tier 2 Emission Standards per NSPS IIII	12.659	3.16
VOC	5.330	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW	0.603	0.151
$PM/PM_{10}/PM_{2.5}$	6.397	Tier 2 Emission Standards per NSPS IIII	0.723	0.181
SO_2	0.208	AP-42 Table 3.4-1	0.023	0.006
CO_2	22,501	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2	2,544	636.05
CH_4	0.913	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2	0.103	0.026
N_2O	0.183	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2	0.021	0.005
CO_2e	22,575	40 CFR 98, Subpart A	2,553	638.14
Hazardous Air Pollutants				
Acetaldehyde	3.45E-03	AP-42 Table 3.4-3	3.90E-04	9.76E-05
Acrolein	1.08E-03	AP-42 Table 3.4-3	1.22E-04	3.05E-05
Benzene	1.06E-01	AP-42 Table 3.4-3	1.20E-02	3.01E-03
Formaldehyde	1.08E-02	AP-42 Table 3.4-3	1.22E-03	3.06E-04
Naphthalene	1.78E-02	AP-42 Table 3.4-4	2.01E-03	5.04E-04
PAH	2.91E-02	AP-42 Table 3.4-4	3.28E-03	8.21E-04
Toluene	3.85E-02	AP-42 Table 3.4-3	4.35E-03	1.09E-03
Xylenes	2.64E-02	AP-42 Table 3.4-3	2.99E-03	7.48E-04
Total HAP	0.233	AP-42 Table 3.4-3	2.64E-02	6.60E-03

Sample Calculations:

NOx (lb/hr) = 199.388 lb/Mgal * 0.113 Mgal/hr = 22.545 lb/hr NOx

NOx (tpy) = 22.545 lb/hr * 500 hr/yr / 2,000 lb/ton = 5.64 tpy NOx

11. Derivation of Emissions Factors and Calculations for EU 22: 310 HP Diesel Pump/Engine

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 22: 310 HP Diesel Pump/Engine are documented in this section.

Emission Unit ID:	22
Emission Unit Name:	310 HP Diesel Pump/Engine
Emission Unit Description:	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp
Equipment ID (SI):	COMB0012

11.1 Process Unit(s)

Process ID:	01
EU ID - PID:	22-01
Process Description:	Diesel Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-22
Stack Description:	TBD
Applicable Regulation:	NSPS IIII, RICE MACT, 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	20100102
SCC Description:	Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)
SCC Units:	1000 Gallons Distillate Oil (Diesel) Burned

11.2 310 HP Diesel Pump/Engine Operational Data and Specifications for 22-01

Engine Rating	**310**	**bhp**	Maximum required engine power output
Annual Operating Hours	500	hr/yr	The PTE of emergency engines may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	136.20	MMBtu/Mgal	Average for EKPC Fuel Oil
HHV used for AP-42 1.4 Emission Factors	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19300 Btu/lb * 7.1 lb/gallon = 137,000 Btu/gallon
40 CFR 98, Subpart C Emission Factors	138.00	MMBtu/Mgal	HHV per 40 CFR 98 Subpart C
Avg Brake-Specific Fuel Consumption	7,000	Btu/hp-hr	AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines, Table 3.3-1 Footnote a
Maximum Fuel Consumption	0.016	Mgal/hr	= 310 bhp * 7,000 Btu/hp-hr / 10^6 Btu/MMBtu / 136.2 MMBtu/Mgal

11.3 Derivation and Documentation of Emission Factors for 22-01

> While the exact make and model of the fire pump engine is not known, it is assumed that the engine will be compliant with the NSPS IIII Table 4 emission standards for engine ratings greater than 300 HP, but less than 600 HP. Emission factors for pollutants without Tier 2 emission standards are from AP-42, Section 3.3 Gasoline and Diesel Industrial Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO_2 greenhouse gases).

Emission factor for NO_X + NMHC:	4.0	g/kW-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)

> A separate VOC and NO_X emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NO_X factor in AP-42 Table 3.3-1 (10/1996 edition).

Sum of AP-42 NO_X and TOC emission factors:	0.034	lb/hp-hr	AP-42 Table 3.3-1 for Diesel Fuel
Ratio of NO_X factor to sum of NO_X and TOC factors:	0.925		= 0.031 / 0.034 lb/hp-hr
Ratio of TOC factor to sum of NO_X and TOC factors:	0.075		= 0.00247 + 4.41 E-05 / 0.034

NO_X

Emission factor for NO_X:	2.76	g/hp-hr	= 4 g/kW-hr * 0.925 / 1.341 hp/kW
NO_X emission factor in terms of SCC units:	118.35	lb/Mgal	= 2.76 g/hp-hr * 310 bhp / 0.016 Mgal/hr / 453.593 g/lb

VOC

Emission factor for VOC:	0.22	g/hp-hr	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW
VOC emission factor in terms of SCC units:	9.60	lb/Mgal	= 0.22 g/hp-hr * 310 bhp / 0.016 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	2.60	g/hp-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
CO emission factor in terms of SCC units:	111.529	lb/Mgal	= 2.60 g/hp-hr * 310 bhp / 0.016 Mgal/hr / 453.593 g/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.15	g/hp-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	6.434	lb/Mgal	= 0.15 g/hp-hr * 310 bhp / 0.016 Mgal/hr / 453.593 g/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, the ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF * 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu x 137 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A, Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1	
CH_4	28	89 FR 42218, May 14, 2024
N_2O	265	89 FR 42218, May 14, 2024

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,501	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.913	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.183	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.20	22,575	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

11.3.1 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.3-2 (10/96 Edition). Emission factors are converted from lb/MMBtu as provided in AP-42 to lb/Mgal as applicable to the SCC designation.

Pollutant	CAS #	HAP?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)
1,3-Butadiene	106-99-0	Y	3.91E-05	5.36E-03
Acetaldehyde	75-07-0	Y	7.67E-04	1.05E-01
Acrolein	107-02-8	Y	9.25E-05	1.27E-02
Benzene	71-43-2	Y	9.33E-04	1.28E-01
Formaldehyde	50-00-0	Y	1.18E-03	1.62E-01
Naphthalene	91-20-3	Y	8.48E-05	1.16E-02
PAH		Y	1.68E-04	2.30E-02
Toluene	108-88-3	Y	4.09E-04	5.60E-02
Xylenes	1330-20-7	Y	2.85E-04	3.91E-02

11.4 Potential Emissions Summary for 22-01

Pollutant	Emission Factor (lb/Mgal)	Emission Factor Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	118.351	= 4 g/kW-hr * 0.925 / 1.341 hp/kW	1.886	0.471
CO	111.529	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	1.777	0.444
VOC	9.598	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW	0.153	0.038
$PM/PM_{10}/PM_{2.5}$	6.434	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	0.103	0.026
SO_2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	0.0033	0.0008
CO_2	22,501	40 CFR 98, Subpart C, Table C-1	358.5	89.6
CH_4	0.913	40 CFR 98, Subpart C, Table C-2	0.015	0.004
N_2O	0.183	40 CFR 98, Subpart C, Table C-2	0.0029	0.0007
CO_2e	22,575	40 CFR 98, Subpart A	359.7	89.9
Hazardous Air Pollutants				
1,3-Butadiene	5.36E-03	AP-42 Table 3.3-2	8.54E-05	2.13E-05
Acetaldehyde	1.05E-01	AP-42 Table 3.3-2	1.67E-03	4.19E-04
Acrolein	1.27E-02	AP-42 Table 3.3-2	2.02E-04	5.05E-05
Benzene	1.28E-01	AP-42 Table 3.3-2	2.04E-03	5.09E-04
Formaldehyde	1.62E-01	AP-42 Table 3.3-2	2.58E-03	6.44E-04
Naphthalene	1.16E-02	AP-42 Table 3.3-2	1.85E-04	4.63E-05
PAH	2.30E-02	AP-42 Table 3.3-2	3.67E-04	9.17E-05
Toluene	5.60E-02	AP-42 Table 3.3-2	8.93E-04	2.23E-04
Xylenes	3.91E-02	AP-42 Table 3.3-2	6.22E-04	1.56E-04
Total HAP	0.542	AP-42 Table 3.3-2	8.64E-03	2.16E-03

Sample Calculations:
NOx (lb/hr) = 118.351 lb/Mgal * 0.016 Mgal/hr = 1.886 lb/hr NOx
NOx (tpy) = 1.886 lb/hr * 500 hr/yr / 2,000 lb/ton = 0.471 tpy NOx

12. Derivation of Emissions Factors and Calculations for EU 29A: Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 29A: Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each) are documented in this section.

Emission Unit ID:	29A
Emission Unit Name:	Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each)
Emission Unit Description:	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)
Equipment ID (SI):	EQPT0026

12.1 Process Unit(s)

Process ID:	01
EU ID - PID:	29A-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-29A
Stack Description:	TBD
Applicable Regulation:	401 KAR 59:015; 401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes
Source Classification Code	
SCC:	39990003
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units:	Million Cubic Feet Natural Gas Burned

12.2 Indirect-fired HVAC Heaters (5.5 MMBtu/hr Each) Operational Data and Specifications for 29A-01

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity per Unit	**5.5**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0052	MMscf/hr	= 5.5 MMBtu/hr / 1060 Btu/scf
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	
Total Number of Units	7	HVAC Units at 5.5 MMBtu/hr	
Total Heat Input for all Units	39	MMBtu/hr	
Total Heat Input for all Units	3.63E-02	MMscf/hr	

12.3 Derivation and Documentation of Emission Factors for 29A-01

12.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Standard Temperature	68	°F	STP Parameters
	528	°R	
Standard Pressure	1	atm	STP Parameters
Universal Gas Constant	0.7302	cf-atm/(lbmol-°R)	Constant
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Mass Conversion	7,000	gr/lb	
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

12.3.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.098	100	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
CO	00630-08-0	0.082	84	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Section 1.4 Table 1.4-2 (7/98), difference between EPA Speciate database for total PM and AP-42 for filterable
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	= 0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb S/lbmol * 10,000 Ccf/MMscf
H_2SO_4	7664-93-9	0.0001	0.109	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

12.3.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

12.4 Potential Emissions Summary for 29A-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions per Unit (lb/hr)	(tpy)	Total Potential Emissions (lb/hr)	(tpy)
NO_x	100	AP-42 Table 1.4-1	0.519	2.273	3.632	15.908
CO	84	AP-42 Table 1.4-1	0.436	1.909	3.051	13.363
VOC	5.5	AP-42 Table 1.4-2	0.029	0.125	0.200	0.875
$PM/PM_{10}/PM_{2.5}$-Filt	1.9	AP-42 Table 1.4-2	0.010	0.043	0.069	0.302
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate	0.008	0.036	0.057	0.250
$PM/PM_{10}/PM_{2.5}$ Total	3.47	AP-42 Table 1.4-2	0.018	0.079	0.126	0.552
SO_2	1.43	Pipeline spec conversion	0.007	0.032	0.052	0.227
H_2SO_4	0.109	Pipeline spec conversion	5.67E-04	2.48E-03	3.97E-03	1.74E-02
Lead	0.0005	AP-42, Table 1.4-2	2.59E-06	1.14E-05	1.82E-05	7.95E-05
CO_2	120019	40 CFR 98, Table C-1	623	2,728	4,359	19,093
CH_4	2.26	40 CFR 98, Table C-2	0.012	0.051	0.082	0.360
N_2O	0.226	40 CFR 98, Table C-2	0.001	0.005	0.008	0.036
CO_2e	120142	40 CFR 98, Subpart A	623	2,730	4,364	19,113
Hazardous Air Pollutants						
Total HAP	1.89	Sum of HAPs	0.010	0.043	0.069	0.300
Benzene	2.1E-03	AP-42, Table 1.4-3	1.09E-05	4.77E-05	7.63E-05	3.34E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	6.23E-06	2.73E-05	4.36E-05	1.91E-04
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	3.89E-04	1.70E-03	2.72E-03	1.19E-02
Hexane	1.80	AP-42, Table 1.4-3	9.34E-03	4.09E-02	6.54E-02	2.86E-01
Naphthalene	6.1E-04	AP-42, Table 1.4-3	3.17E-06	1.39E-05	2.22E-05	9.70E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	1.76E-05	7.73E-05	1.23E-04	5.41E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.04E-06	4.55E-06	7.26E-06	3.18E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	5.71E-06	2.50E-05	4.00E-05	1.75E-04
Chromium	1.4E-03	AP-42, Table 1.4-4	7.26E-06	3.18E-05	5.08E-05	2.23E-04
Manganese	3.8E-04	AP-42, Table 1.4-4	1.97E-06	8.64E-06	1.38E-05	6.05E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	1.35E-06	5.91E-06	9.44E-06	4.14E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	1.09E-05	4.77E-05	7.63E-05	3.34E-04

Sample Calculations (per Unit):

NOx (lb/hr) = 100 lb/MMscf x 0.0052 MMscf/hr = 0.519 lb/hr NOx

NOx (tpy) = 0.519 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.273 tpy NOx

13. Derivation of Emissions Factors and Calculations for EU 29B: Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 29B: Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each) are documented in this section.

Emission Unit ID:	29B
Emission Unit Name:	Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each)
Emission Unit Description:	14 Indirect-Fired HVAC Heaters (0.061 MMBtu/hr each)
Equipment ID (SI):	EQPT0027

13.1 Process Unit(s)

Process ID:	01
EU ID - PID:	29B-01
Process Description:	Natural Gas Firing
Control Device ID:	N/A
Control Device Description:	N/A
Stack ID:	S-29B
Stack Description:	TBD
Applicable Regulation:	401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	No
Count Emissions for PTE?	Yes
Source Classification Code	
SCC:	39990003
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units:	Million Cubic Feet Natural Gas Burned

13.2 Indirect-fired HVAC Heaters (0.061 MMBtu/hr Each) Operational Data and Specifications for 29B-01

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity per Unit	**0.061**	**MMBtu/hr**	
NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
Max Gas Firing Rate at Average HHV	0.0001	MMscf/hr	= 0.061 MMBtu/hr / 1060 Btu/scf
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for 40 CFR 98, Subpart C Emission Factors	1,026	Btu/scf	
Total Number of Units	14	HVAC Units at 0.061 MMBtu/hr	
Total Heat Input for all Units	0.854	MMBtu/hr	
Total Heat Input for all Units	8.06E-04	MMscf/hr	

13.3 Derivation and Documentation of Emission Factors for 29B-01

13.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Standard Temperature	68	°F	STP Parameters
	528	°R	
Standard Pressure	1	atm	STP Parameters
Universal Gas Constant	0.7302	cf-atm/(lbmol-°R)	Constant
Molar Volume (at STP)	385.5	scf/lbmol	= 0.7302 cf-atm/(lbmol-°R) * 528 °R / 1.0 atm
Mass Conversion	7,000	gr/lb	
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for EKPC inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

13.3.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NO_x	10102-44-0	0.098	100	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
CO	00630-08-0	0.082	84	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
$PM/PM_{10}/PM_{2.5}$-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Section 1.4 Table 1.4-2 (7/98), difference between EPA Speciate database for total PM and AP-42 for filterable
$PM/PM_{10}/PM_{2.5}$ Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
SO_2	07446-09-5	0.0013	1.427	=0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb
H_2SO_4	7664-93-9	1.03E-04	0.109	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO_2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e		117.10	120,142	= CO2 EF * CO2 GWP + CH4 EF * CH4 GWP + N2O EF * N2O GWP

13.3.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.80
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

13.4 Potential Emissions Summary for 29B-01

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions per Unit (lb/hr)	Potential Emissions per Unit (tpy)	Total Potential Emissions (lb/hr)	Total Potential Emissions (tpy)
NO_x	100	AP-42 Table 1.4-1	0.006	0.025	0.081	0.353
CO	84	AP-42 Table 1.4-1	0.005	0.021	0.068	0.296
VOC	5.5	AP-42 Table 1.4-2	3.17E-04	1.39E-03	4.43E-03	1.94E-02
$PM/PM_{10}/PM_{2.5}$-Filt	1.90	AP-42 Table 1.4-2	1.09E-04	4.79E-04	1.53E-03	6.70E-03
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA	9.03E-05	3.96E-04	1.26E-03	5.54E-03
$PM/PM_{10}/PM_{2.5}$ Total	3.47	AP-42 Table 1.4-2	2.00E-04	8.75E-04	2.80E-03	1.22E-02
SO_2	1.427	Pipeline spec conversion	8.21E-05	3.60E-04	1.15E-03	5.04E-03
H_2SO_4	0.109	Pipeline spec conversion	6.29E-06	2.75E-05	8.80E-05	3.85E-04
Lead	0.0005	AP-42, Table 1.4-2	2.88E-08	1.26E-07	4.03E-07	1.76E-06
CO_2	120019	40 CFR 98, Table C-1	7	30	96.694	423.521
CH_4	2.26	40 CFR 98, Table C-2	1.30E-04	5.70E-04	1.82E-03	7.98E-03
N_2O	0.226	40 CFR 98, Table C-2	1.30E-05	5.70E-05	1.82E-04	7.98E-04
CO_2e	120142	40 CFR 98, Subpart A	7	30	96.794	423.956
Hazardous Air Pollutants						
Total HAP	1.89	Sum of HAPs	1.09E-04	4.76E-04	1.52E-03	6.66E-03
Benzene	2.1E-03	AP-42, Table 1.4-3	1.21E-07	5.29E-07	1.69E-06	7.41E-06
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	6.91E-08	3.02E-07	9.67E-07	4.23E-06
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	4.32E-06	1.89E-05	6.04E-05	2.65E-04
Hexane	1.80	AP-42, Table 1.4-3	1.04E-04	4.54E-04	1.45E-03	6.35E-03
Naphthalene	6.1E-04	AP-42, Table 1.4-3	3.51E-08	1.54E-07	4.91E-07	2.15E-06
Toluene	3.4E-03	AP-42, Table 1.4-3	1.96E-07	8.57E-07	2.74E-06	1.20E-05
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.15E-08	5.04E-08	1.61E-07	7.06E-07
Cadmium	1.1E-03	AP-42, Table 1.4-4	6.33E-08	2.77E-07	8.86E-07	3.88E-06
Chromium	1.4E-03	AP-42, Table 1.4-4	8.06E-08	3.53E-07	1.13E-06	4.94E-06
Manganese	3.8E-04	AP-42, Table 1.4-4	2.19E-08	9.58E-08	3.06E-07	1.34E-06
Mercury	2.6E-04	AP-42, Table 1.4-4	1.50E-08	6.55E-08	2.09E-07	9.17E-07
Nickel	2.1E-03	AP-42, Table 1.4-4	1.21E-07	5.29E-07	1.69E-06	7.41E-06

Sample Calculations (per Unit):

NOx (lb/hr) = 100 lb/MMscf x 0.0001 MMscf/hr = 0.006 lb/hr NOx

NOx (tpy) = 0.006 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 0.025 tpy NOx

14. Derivation of Emissions Factors and Calculations for EU 26A: 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 26A: 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs and EU 26B: 1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs are documented in this section.

Emission Unit ID: 26A
Emission Unit Name: 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs
Emission Unit Description: 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs
Equipment ID (SI): EQPT0022

14.1 Process Unit(s)

Process ID: 01
EU ID - PID: 26A-01
Process Description: Breathing Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-26A
Stack Description: TBD
Applicable Regulation: 401 KAR 63:020; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: 02
EU ID - PID: 26A-02
Process Description: Working Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-26A
Stack Description: TBD
Applicable Regulation: 401 KAR 63:020; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

14.2 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs Operational Data and Specifications for 26A-01

Max Annual Operating Hours	1,080	hr/yr	
Tank Height	40	ft	Design specification
Tank Diameter	84	ft	Design specification
Tank Volume	221,670.78	ft^3	Volume of cylinder
	1,658,213	gal	Unit conversion
Fuel Oil Throughput per Tank	20,590,514	gal/yr	CCGT annual fuel consumption (based on 1,080 hr/yr): 19.065 Mgal/hr * 1080 operating hrs/yr * 1,000 gal/Mgal
	19,065.29	gal/hr	Assuming maximum FO operation (i.e., 1,080 hr/yr)
Turnovers	12.42	turnovers/yr	= 20,590,514 gal/yr / 1,658,213 gal
True Vapor Pressure	0.0066	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	57.78	°F	Calculated by TankESP
Average Liquid Surface Temperature	60.40	°F	Calculated by TankESP

14.3 Potential Emissions Summary for 26A-01

Storage Tank ID	Pollutant	Standing Loss Emission Factor (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
CCGT FO Tank #1	VOC	0.233	0.021	TankESP analysis using methodology presented in AP-42	386.632	433.017	0.759	0.410
CCGT FO Tank #2	VOC	0.233	0.021	TankESP analysis using methodology presented in AP-42	386.632	433.017	0.759	0.410

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

Sample Calculation of Estimated Emissions - Fixed-Roof Tanks

The emissions estimates calculated below are based on EPA's AP-42 Chapter 7.1 (Post 2018) emission factors and equations,

Company:
Location: **EKPC Cooper Station**
Calculations for Tank No.: **EU26**
Emission estimates per EPA's AP-42 Chapter 7.1 (Post 2018), for: **annual 2024**

Meteorological Data:

Avg Atmos Pressure, Pa:	**14.184912**	psia
Avg Ambient Temp, Taa:	**55.552322**	degrees F
Avg Daily Temp Range, ΔTa:	**17.904699**	degrees F
Avg Daily Solar Insolation, I:	**1281.9783**	Btu / ft^2 day

Tank Data:

Tank Type:	**FixedRoof**		shell color:	**light gray paint**
Average alpha:	**0.58**		shell condition:	**Average**
Tank Diameter:	**84**	ft	shell alpha:	**0.58**
Tank Height:	**40**	ft	roof color:	**light gray paint**
Maximum Fill Height:	**37.5**	ft	roof condition:	**Average**
Minimum Liquid Level:	**1**	ft	roof alpha:	**0.58**
Net Working Height:	**36.5**	ft		
Fixed Roof Type:	**self-supporting (dome)**		effective roof height:	**5.8937** ft
Average outage, H_{VO}:	**26.643696**	ft	Hvo:	**26.644** ft
Max Vent Setting:	**0.03**	psig		
Min Vent Setting:	**-0.03**	psig		

Service Data:

Service (stored liquid):	**Distillate fuel oil no. 2**		Vapor Pressure Constants:
Product Factor, K_P:	**1**		
Reid VaporPressure:		psi (if specified)	A: **12.101**
ASTM Distillation Slope:		(if specified)	B: **8907**
Molecular Weight, M_V:	**130**	lb/lb-mol	C:
Liquid Bulk Temp, Tb:	**57.8**	degrees F	
Constant Temp Tank?	**NO**		tank must be insulated for temperature to be constant
Liquid Bulk Temp Basis?	calculated from ambient, per AP-42 equation 1-31		
Liquid Surface Temp, Tla:	**60.4**	degrees F	per AP-42 equation 1-27, 1-28, 1-29
True Vapor Pressure, P:	**0.0066**	psia	per AP-42 equation 1-24, 1-25, 1-26
Stock Vapor Density, W_V:	**0.00015**	lb/ft^3	per AP-42 equation 1-22

Heating Cycles:

Vapor Space Temp., Tv:	63.01663	degree F	per AP-42 equation 1-32, 1-33, 1-34
Max Liquid Bulk Temp:		degrees F	
Min Liquid Bulk Temp:		degrees F	
Heating cycle frequency:		days	

Operational Data:

Throughput:	**506,686**	bbl per year
Days this Period:	**366**	days
Turnover Rate:	**14.0**	turnovers per year
Turnover Factor, K_N:	**1.000**	

Calculated Values:

Vapor Space Expansion Factor, $K_E = \{\Delta T_V / (T + 459.67)\} + \{(\Delta P_V - \Delta P_B) / (P_A - P)\}$ AP-42 eqn 1-5

where:

ΔT_V = 26.76305 deg F (deg R); daily temperature range in the vapor space AP-42 eqn 1-6, 1-7, 1-8

Tlx = 67.09 deg F Pvx = 0.008 psia

Tln = 53.71 deg F Pvn = 0.005 psia

ΔP_V = **0.00291** psia

ΔP_B = 0.06 psi; vent setting range

K_E = **0.047434**

Vented Vapor Saturation Factor, $K_S = 1 / (1+ 0.053\ P\ H_{VO})$ AP-42 eqn 1-21

K_S = **0.99081**

Vent Setting Correction Factor, K_B:

K_B = 1; except when:

$K_N [(P_{BP} + P_A) / (P_I + P_A)] > 1$ AP-42 eqn 1-40

$K_B = [(P_I + P_A)/K_N - P] / [P_{BP} + P_A - P]$ AP-42 eqn 1-41

where:

P_{BP} = 0.03 psig; vent pressure setting

P_I = 0 psig; initial gauge pressure (nominal operating pressure)

K_B = **1**

Control Effi= **0**

Emissions Estimate for: **annual 2024**

Standing Storage Loss:	**386.63**	lb per year	AP-42 eqn 1-4
Working Loss:	**433.02**	lb per year	AP-42 eqn 1-35
Total Emissions (w/o heating cycle loss):	**819.65**	lb per year	AP-42 eqn 1-1
	0.4	tons per year	
Standing Storage Loss(with control):	**386.63**	lb per year	
Working Loss(with control):	**433.02**	lb per year	
Total Emissions(with control):	**819.65**	lb per year	
	0.410	tons per year	

15. Derivation of Emissions Factors and Calculations for EU 27: 1,000 gallon Diesel Storage Tank

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 27: 1,000 gallon Diesel Storage Tank are documented in this section.

Emission Unit ID: 27
Emission Unit Name: 1,000 gallon Diesel Storage Tank
Emission Unit Description: 1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine
Equipment ID (SI): EQPT0024

15.1 Process Unit(s)

Process ID: 01
EU ID - PID: 27-01
Process Description: Breathing Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-27
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: 02
EU ID - PID: 27-02
Process Description: Working Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-27
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

15.2 1,000 gallon Diesel Storage Tank Operational Data and Specifications for 27-01

Max Annual Operating Hours	8,760	hr/yr	
Tank Volume	1,000	gal	Design specification
	134	ft^3	Unit Conversion: 1000 gal * 7.48 ft3/gal
Tank Height	4.40	ft	Design specification
Tank Diameter	8.80	ft	Design specification
Fuel Oil Throughput	56,535	gal/yr	Emergency diesel engine annual fuel consumption (based on 500 hr/yr): 0.113 Mgal/hr * 500 operating hrs/yr * 1,000 gal/Mgal
	6.45	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	56.53	turnovers/yr	= 56,535 gal/yr / 1,000 gal
True Vapor Pressure	0.0060	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	56.51	°F	Calculated by TankESP
Average Liquid Surface Temperature	57.63	°F	Calculated by TankESP

15.3 Potential Emissions Summary for 27-01

Storage Tank	Pollutant	Standing Loss Emission Factor (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Emergency Generator Belly Tank	VOC	0.285	0.013	TankESP analysis using methodology presented in AP-42 Section 7.1	0.285	0.758	1.19E-04	5.22E-04

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

Sample Calculation of Estimated Emissions - Fixed-Roof Tanks

The emissions estimates calculated below are based on EPA's AP-42 Chapter 7.1 (Post 2018) emission factors and equations,

Company:
Location: **EKPC Cooper Station**
Calculations for Tank No.: **EU27**
Emission estimates per EPA's AP-42 Chapter 7.1 (Post 2018), for: **annual 2024**

Meteorological Data:

Avg Atmos Pressure, Pa:	**14.184912**	psia
Avg Ambient Temp, Taa:	**55.552322**	degrees F
Avg Daily Temp Range, ΔTa:	**17.904699**	degrees F
Avg Daily Solar Insolation, I:	**1281.9783**	Btu / ft^2 day

Tank Data:

Tank Type:	**FixedRoof**		shell color:	**white paint**
Average alpha:	**0.25**		shell condition:	**Average**
Tank Diameter:	**8.8**	ft	shell alpha:	**0.25**
Tank Height:	**4.4**	ft	roof color:	**white paint**
Maximum Fill Height:	**3.4**	ft	roof condition:	**Average**
Minimum Liquid Level:	**1**	ft	roof alpha:	**0.25**
Net Working Height:	**2.4**	ft		
Fixed Roof Type:	**self-supporting (dome)**		effective roof height:	**0.6036** ft
Average outage, H_{VO}:	**2.803596**	ft	Hvo:	**2.8036** ft
Max Vent Setting:	**0.03**	psig		
Min Vent Setting:	**-0.03**	psig		

Service Data:

Service (stored liquid):	**Distillate fuel oil no. 2**			
Product Factor, K_P:	**1**			Vapor Pressure Constants:
Reid VaporPressure:		psi	(if specified)	A: **12.101**
ASTM Distillation Slope:			(if specified)	B: **8907**
Molecular Weight, M_V:	**130**	lb/lb-mol		C:
Liquid Bulk Temp, Tb:	**56.5**	degrees F		
Constant Temp Tank?	**NO**		tank must be insulated for temperature to be constant	
Liquid Bulk Temp Basis?	calculated from ambient, per AP-42 equation 1-31			
Liquid Surface Temp, Tla:	**57.6**	degrees F	per AP-42 equation 1-27, 1-28, 1-29	
True Vapor Pressure, P:	**0.0060**	psia	per AP-42 equation 1-24, 1-25, 1-26	
Stock Vapor Density, W_V:	**0.00014**	lb/ft^3	per AP-42 equation 1-22	
Heating Cycles: Vapor Space Temp., Tv:	58.74658	degree F	per AP-42 equation 1-32, 1-33, 1-34	
Max Liquid Bulk Temp:		degrees F		
Min Liquid Bulk Temp:		degrees F		
Heating cycle frequency:		days		

Operational Data:

Throughput:	**1,093**	bbl per year
Days this Period:	**366**	days
Turnover Rate:	**41.9**	turnovers per year
Turnover Factor, K_N:	**0.883**	

Calculated Values:

Vapor Space Expansion Factor, $K_E = \{\Delta T_V / (T + 459.67)\} + \{(\Delta P_V - \Delta P_B) / (P_A - P)\}$ AP-42 eqn 1-5

where:

ΔT_V = 19.00585 deg F (deg R); daily temperature range in the vapor space AP-42 eqn 1-6, 1-7, 1-8

Tlx = 62.38 deg F Pvx = 0.007 psia

Tln = 52.88 deg F Pvn = 0.005 psia

ΔP_V = **0.001901** psia

ΔP_B = 0.06 psi; vent setting range

K_E = **0.032643**

Vented Vapor Saturation Factor, $K_S = 1 / (1 + 0.053\ P\ H_{VO})$ AP-42 eqn 1-21

K_S = **0.99911**

Vent Setting Correction Factor, K_B:

K_B = 1; except when:

$K_N [(P_{BP} + P_A) / (P_I + P_A)] > 1$ AP-42 eqn 1-40

$K_B = [(P_I + P_A)/K_N - P] / [P_{BP} + P_A - P]$ AP-42 eqn 1-41

where:

P_{BP} = 0.03 psig; vent pressure setting

P_I = 0 psig; initial gauge pressure (nominal operating pressure)

K_B = **1**

Control Effi= **0**

Emissions Estimate for: **annual 2024**

Standing Storage Loss:	**0.29**	lb per year	AP-42 eqn 1-4
Working Loss:	**0.76**	lb per year	AP-42 eqn 1-35
Total Emissions (w/o heating cycle loss):	**1.04**	lb per year	AP-42 eqn 1-1
	5.22E-04	tons per year	
Standing Storage Loss(with control):	**0.29**	lb per year	
Working Loss(with control):	**0.76**	lb per year	
Total Emissions(with control):	**1.04**	lb per year	
	5.22E-04	tons per year	

16. Derivation of Emissions Factors and Calculations for EU 28: 350 gallon Diesel Storage Tank

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 28: 350 gallon Diesel Storage Tank are documented in this section.

Emission Unit ID: 28
Emission Unit Name: 350 gallon Diesel Storage Tank
Emission Unit Description: 350 Gallon Diesel Storage Tank for Fire Pump Engine
Equipment ID (SI): EQPT0025

16.1 Process Unit(s)

Process ID: 01
EU ID - PID: 28-01
Process Description: Breathing Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-28
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: 02
EU ID - PID: 28-02
Process Description: Working Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-28
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

16.2 350 gallon Diesel Storage Tank Operational Data and Specifications for 28-01

Max Annual Operating Hours	8,760	hr/yr	
Tank Volume	350	gal	Design specification
	46.8	ft^3	Unit Conversion: 350 gal * 7.48 ft3/gal
Tank Height	3.10	ft	Design specification
Tank Diameter	6.20	ft	Design specification
Fuel Oil Throughput	7,966	gal/yr	Emergency diesel fire pump engine annual fuel consumption (based on 500 hr/yr): 0.016 Mgal/hr * 500 operating hrs/yr * 1,000 gal/Mgal
	0.91	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	22.76	turnovers/yr	= 7,966 gal/yr / 0,350 gal
True Vapor Pressure	0.0060	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	56.51	°F	Calculated by TankESP
Average Liquid Surface Temperature	57.63	°F	Calculated by TankESP

16.3 Potential Emissions Summary for 28-01

Storage Tank	Pollutant	Standing Loss Emission Factor (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	(tpy)
Fire Pump Belly Tank	VOC	0.265	0.019	TankESP analysis using methodology presented in AP-42 Section 7.1	0.093	0.149	2.76E-05	1.21E-04

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

Sample Calculation of Estimated Emissions - Fixed-Roof Tanks

The emissions estimates calculated below are based on EPA's AP-42 Chapter 7.1 (Post 2018) emission factors and equations,

Company:
Location: **EKPC Cooper Station**
Calculations for Tank No.: **EU28**
Emission estimates per EPA's AP-42 Chapter 7.1 (Post 2018), for: **annual 2024**

Meteorological Data:

Avg Atmos Pressure, Pa:	**14.184912**	psia
Avg Ambient Temp, Taa:	**55.552322**	degrees F
Avg Daily Temp Range, ΔTa:	**17.904699**	degrees F
Avg Daily Solar Insolation, I:	**1281.9783**	Btu / ft^2 day

Tank Data:

Tank Type:	**FixedRoof**		shell color:	**white paint**
Average alpha:	**0.25**		shell condition:	**Average**
Tank Diameter:	**6.2**	ft	shell alpha:	**0.25**
Tank Height:	**3.1**	ft	roof color:	**white paint**
Maximum Fill Height:	**2.1**	ft	roof condition:	**Average**
Minimum Liquid Level:	**1**	ft	roof alpha:	**0.25**
Net Working Height:	**1.1**	ft		
Fixed Roof Type:	**self-supporting (dome)**		effective roof height:	**0.2852** ft
Average outage, H_{VO}:	**1.8351646**	ft	Hvo:	**1.8352** ft
Max Vent Setting:	**0.03**	psig		
Min Vent Setting:	**-0.03**	psig		

Service Data:

Service (stored liquid):	**Distillate fuel oil no. 2**			
Product Factor, K_P:	**1**		Vapor Pressure Constants:	
Reid VaporPressure:		psi	(if specified)	A: **12.101**
ASTM Distillation Slope:			(if specified)	B: **8907**
Molecular Weight, M_V:	**130**	lb/lb-mol		C:
Liquid Bulk Temp, Tb:	**56.5**	degrees F		
Constant Temp Tank?	**NO**		tank must be insulated for temperature to be constant	
Liquid Bulk Temp Basis?	calculated from ambient, per AP-42 equation 1-31			
Liquid Surface Temp, Tla:	**57.6**	degrees F	per AP-42 equation 1-27, 1-28, 1-29	
True Vapor Pressure, P:	**0.0060**	psia	per AP-42 equation 1-24, 1-25, 1-26	
Stock Vapor Density, W_V:	**0.00014**	lb/ft^3	per AP-42 equation 1-22	

Heating Cycles:

Vapor Space Temp., Tv:	58.74658	degree F	per AP-42 equation 1-32, 1-33, 1-34
Max Liquid Bulk Temp:		degrees F	
Min Liquid Bulk Temp:		degrees F	
Heating cycle frequency:		days	

Operational Data:

Throughput:	**190**	bbl per year
Days this Period:	**366**	days
Turnover Rate:	**32.0**	turnovers per year
Turnover Factor, K_N:	**1.000**	

Calculated Values:

Vapor Space Expansion Factor, $K_E = \{\Delta T_V / (T + 459.67)\} + \{(\Delta P_V - \Delta P_B) / (P_A - P)\}$ AP-42 eqn 1-5

where:

ΔT_V = 19.00585 deg F (deg R); daily temperature range in the vapor space AP-42 eqn 1-6, 1-7, 1-8

Tlx = 62.38 deg F Pvx = 0.007 psia

Tln = 52.88 deg F Pvn = 0.005 psia

ΔP_V = **0.001901** psia

ΔP_B = 0.06 psi; vent setting range

K_E = **0.032643**

Vented Vapor Saturation Factor, $K_S = 1 / (1+ 0.053\ P\ H_{VO})$ AP-42 eqn 1-21

K_S = **0.999417**

Vent Setting Correction Factor, K_B:

K_B = 1; except when:

$K_N [(P_{BP} + P_A) / (P_I + P_A)] > 1$ AP-42 eqn 1-40

$K_B = [(P_I + P_A)/K_N - P] / [P_{BP} + P_A - P]$ AP-42 eqn 1-41

where:

P_{BP} = 0.03 psig; vent pressure setting

P_I = 0 psig; initial gauge pressure (nominal operating pressure)

K_B = **1**

Control Effi= **0**

Emissions Estimate for:	**annual 2024**		
Standing Storage Loss:	**0.09**	lb per year	AP-42 eqn 1-4
Working Loss:	**0.15**	lb per year	AP-42 eqn 1-35
Total Emissions (w/o heating cycle loss):	**0.24**	lb per year	AP-42 eqn 1-1
	1.21E-04	tons per year	
Standing Storage Loss(with control):	**0.09**	lb per year	
Working Loss(with control):	**0.15**	lb per year	
Total Emissions(with control):	**0.24**	lb per year	
	1.21E-04	tons per year	

17. Derivation of Emissions Factors and Calculations for EU 32: CCGT Haul Roads

> Fugitive PM emissions potentially caused due to increased vehicle movement on the existing and new paved roads at the plant are estimated in this section using methodologies of AP-42 Section 13.2.1. Emissions are expressed as a function of vehicle miles traveled (VMT).

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 32: CCGT Haul Roads are documented in this section.

Emission Unit ID: 32
Emission Unit Name: CCGT Haul Roads
Emission Unit Description: CCGT Haul Roads
Equipment ID (SI): AREA0003

17.1 Process Unit(s)

Process ID: 01
EU ID - PID: 32-01
Process Description: 19% Aqueous Ammonia Delivery
Control Device Description: N/A
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

Process ID: 02
EU ID - PID: 32-02
Process Description: ULSFO Delivery
Control Device Description: N/A
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

Process ID: 03
EU ID - PID: 32-03
Process Description: Water Treatment Building Chemicals Delivery
Control Device Description: N/A
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

Process ID: 04
EU ID - PID: 32-04
Process Description: Cooling Tower Chemicals Delivery
Control Device Description: N/A
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

17.2 Vehicle Miles Traveled Per Year for Each Truck/Vehicle Route

> Road emissions are grouped into one of four categories based on material being hauled. Other trucks are intermittently present for other purposes, but due to the infrequency of these occurrences, emissions associated with this traffic are assumed to be negligible.

> For each material, VMT can be estimated each year based on the total amount of material consumed/delivered, and the approximate weight of material carried per trip.

> Annual material process rate totals listed below are estimates based on required material consumption rates to the CCGT system and chemical feed rates to supporting operations.

Truck Route	Maximum Flow for Both Units (gal/hr)	Refill Truck Capacity (gal/trip)	Empty Truck Weight (ton/truck)	Full Truck Weight (ton/truck)	Average Truck Weight (ton/truck)	Maximum Time for Continuous Operations (hr/yr)	Maximum Annual Usage (gal/yr)	Annual Trips (trips/yr)	Paved Distance Per Trip (VMT/trip)	Paved Distance Traveled (VMT/yr)
19% Aqueous Ammonia Delivery	163.90	6,500	16	32.27	24.14	8,760	1,435,773	220.9	0.79	175.0
ULSFO Delivery	39,408.9	10,000	16	52.76	34.38	1,080	42,561,600	4,256	1.37	5,835
Water Treatment Building Chemicals Delivery										
Truck Type 1	9.9	3,397	16	36.01	26.01	8,760	86,545	25.48	1.12	28.45
Truck Type 2	17.8	3,741	16	36.01	26.01	8,760	155,548	41.58	1.12	46.43
Truck Type 3	6.6	4,065	16	36.01	26.01	8,760	57,905	14.25	1.12	15.91
Truck Type 4	0.03	300	16	18.30	17.15	8,760	257	0.86	1.12	0.96
Cooling Tower Chemicals Delivery										
Truck Type 1	3.6	4,065	16	36.01	26.01	8,760	31,632	7.78	1.39	10.83
Truck Type 2	0.4	2,607	16	36.01	26.01	8,760	3,667	1.41	1.39	1.96

17.3 Summary of Route Parameters

Truck Route	VMT Weighted Average Truck Weight (ton/vehicle)	Total Combined Vehicle Miles Traveled (VMT/yr)	Hourly Average Vehicle Miles Traveled (VMT/hr)
19% Aqueous Ammonia Delivery	24.14	175.0	0.020
ULSFO Delivery	34.38	5,835.3	0.666
Water Treatment Building Chemicals Delivery	25.91	91.74	0.010
Cooling Tower Chemicals Delivery	26.01	12.78	0.001

17.4 Paved Road Emission Factors

The methodology presented in AP-42 Section 13.2.1 (11/2006) was used to derive fugitive PM emission factors for truck traffic on paved road surfaces within the plant.

The following emission factor equation applies: (Equation 1 in AP-42 13.2.1)

$E\ (lb/VMT) = k(sL)^{0.91}(W)^{1.02}$

where:

sL Road surface silt loading 0.6 g/m^2 AP-42 Section 13.2.1, Table 13.2.1-2 ubiquitous baseline silt loading for ADT < 500

	PM	PM_{10}	$PM_{2.5}$	
k Particle Size Multiplier (lb/VMT)	0.011	0.0022	0.00054	AP-42 Table 13.2.1-1

E Emission Factor (lb/VMT)	**PM**	**PM_{10}**	**$PM_{2.5}$**
19% Aqueous Ammonia Delivery	0.178	0.036	0.009
ULSFO Delivery	0.255	0.051	0.013
Water Treatment Building Chemicals Delivery	0.191	0.038	0.009
Cooling Tower Chemicals Delivery	0.192	0.038	0.009

Calculated per Equation (1) in AP-42 Section 13.2.1

17.5 Annual Fugitive PM Emissions from Roads

Parameter/Route	PM	PM_{10}	$PM_{2.5}$
Distance (VMT/hr)			
19% Aqueous Ammonia Delivery	0.020	0.020	0.020
ULSFO Delivery	0.666	0.666	0.666
Water Treatment Building Chemicals Delivery	0.010	0.010	0.010
Cooling Tower Chemicals Delivery	0.001	0.001	0.001
Emission Factor (lb/VMT)			
19% Aqueous Ammonia Delivery	0.178	0.036	0.009
ULSFO Delivery	0.255	0.051	0.013
Water Treatment Building Chemicals Delivery	0.191	0.038	0.009
Cooling Tower Chemicals Delivery	0.192	0.038	0.009
Hourly Emission (lb/hr)			
19% Aqueous Ammonia Delivery	0.004	7.10E-04	1.74E-04
ULSFO Delivery	0.170	0.034	0.008
Water Treatment Building Chemicals Delivery	0.002	4.00E-04	9.83E-05
Cooling Tower Chemicals Delivery	2.80E-04	5.60E-05	1.37E-05
Annual Emission (tpy)			
19% Aqueous Ammonia Delivery	0.016	0.003	7.64E-04
ULSFO Delivery	0.744	0.149	0.037
Water Treatment Building Chemicals Delivery	0.009	0.002	4.30E-04
Cooling Tower Chemicals Delivery	0.001	2.45E-04	6.02E-05
Total Annual Emissions (tpy)	**0.770**	**0.154**	**0.038**

18. Derivation of Emissions Factors and Calculations for EU 33: Natural Gas Piping Fugitives

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 33: Natural Gas Piping Fugitives are documented in this section.

Emission Unit ID:	33
Emission Unit Name:	Natural Gas Piping Fugitives
Emission Unit Description:	Natural Gas Piping Fugitives
Equipment ID (SI):	EQPT0030

18.1 Process Unit(s)

Process ID:	01
EU ID - PID:	33-01
Process Description:	Natural Gas Piping Fugitives - GV Valves
Control Device Description:	N/A
Applicable Regulation:	401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	Yes
Count Emissions for PTE?	Yes
Source Classification Code	
SCC:	30600811
SCC Description:	Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Pipeline Valves: Gas Streams (3-06-008-11)
SCC Units:	Each-Year Valve Operating

Process ID:	02
EU ID - PID:	33-02
Process Description:	Natural Gas Piping Fugitives - Relief Valves
Control Device Description:	N/A
Applicable Regulation:	401 KAR 51:017
Construction Date:	1/1/2027
Fugitive Emissions?	Yes
Count Emissions for PTE?	Yes
Source Classification Code	
SCC:	30600822
SCC Description:	Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Vessel Relief Valves: All Streams (3-06-008-22)
SCC Units:	Each-Year Valve Operating

Process ID: 03
EU ID - PID: 33-03
Process Description: Natural Gas Piping Fugitives - Flanges
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code

SCC: 30600816
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Flanges: All Streams (3-06-008-16)
SCC Units: Each-Year Flange Operating

Process ID: 04
EU ID - PID: 33-04
Process Description: Natural Gas Piping Fugitives - Sampling Connections
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code

SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

18.2 Natural Gas Piping Fugitives Component Counts

> The total component counts below represent new natural gas piping components to be installed as part of the CCGT construction and the Unit 2 co-firing modifications.

Component Type	CCGT	Unit 2 Co-fire	Total Components
Valves	200	470	670
Relief Valves	16	5	21
Flanges	280	1700	1,980
Sampling Connections	2	0	2

18.3 Derivation and Documentation of Emission Factors for 33-01

> The emission factors presented below are from EPA's Protocol for Equipment Leak Emissions Estimates (Document EPA-453/R-95/017, November 1995), Page 2-15. These emission factors are representative of oil and gas production operations and as such are appropriate to use for estimating natural gas piping fugitive emissions.

Component Type	Emission Factor (kg/hr/comp.)[1]	VOC Content of Pipeline Gas (wt. %)	VOC Emission Factor (kg/hr/comp.)[2]	VOC Emission Factor (lb/yr/comp.)	CO2 Content of Pipeline Gas (wt. %)	CO2 Emission Factor (kg/hr/comp.)	CO2 Emission Factor (lb/yr/comp.)	CH4 Content of Pipeline Gas (wt. %)	CH4 Emission Factor (kg/hr/comp.)	CH4 Emission Factor (lb/yr/comp.)
Valves	4.50E-03	1.10%	4.96E-05	0.957	0.43%	1.95E-05	0.376	85.1%	3.83E-03	73.999
Relief Valves[3]	8.80E-03	1.10%	9.70E-05	1.872	0.43%	3.81E-05	0.736	85.1%	7.49E-03	144.709
Flanges	3.90E-04	1.10%	4.30E-06	0.083	0.43%	1.69E-06	0.033	85.1%	3.32E-04	6.413
Sampling Connections	8.80E-03	1.10%	9.70E-05	1.872	0.43%	3.81E-05	0.736	85.1%	7.49E-03	144.709

1 These emission factors exclude non-VOC contributions from methane and ethane.

2 VOC EF = TOC EF * VOC wt. %

3 Emissions from pressure relief valves are rolled into the "Other" category.

18.4 Potential Emissions Summary for 33-01

Pollutant	Emission Factor (lb/yr/comp.)	Basis	Potential Emissions (lb/yr)	Potential Emissions (tpy)
Valves				
VOC	0.957	Document EPA-453/R-95/017, November 1995	642	0.321
CO_2	0.376	Document EPA-453/R-95/017, November 1995	252	0.126
CH_4	73.999	Document EPA-453/R-95/017, November 1995	49,579	24.790
CO_2e	2,072	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	1,388,469	694.234
Relief Valves				
VOC	1.872	Document EPA-453/R-95/017, November 1995	39	0.020
CO_2	0.736	Document EPA-453/R-95/017, November 1995	15	0.008
CH_4	144.709	Document EPA-453/R-95/017, November 1995	3,039	1.519
CO_2e	4,053	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	85,104	42.552
Flanges				
VOC	0.083	Document EPA-453/R-95/017, November 1995	164	0.082
CO_2	0.033	Document EPA-453/R-95/017, November 1995	65	0.032
CH_4	6.413	Document EPA-453/R-95/017, November 1995	12,698	6.349
CO_2e	180	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	355,614	177.807
Sampling Connections				
VOC	1.872	Document EPA-453/R-95/017, November 1995	4	0.002
CO_2	0.736	Document EPA-453/R-95/017, November 1995	1	0.001
CH_4	144.709	Document EPA-453/R-95/017, November 1995	289	0.145
CO_2e	4,053	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	8,105	4.053
Total Potential Emissions				
VOC			**849**	**0.424**
CO_2			**334**	**0.167**
CH_4			**65,606**	**32.80**
CO_2e			**1,837,292**	**919**

19. Derivation of Emissions Factors and Calculations for EU 30: Turbine Circuit Breakers

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 30: Turbine Circuit Breakers are documented in this section.

Emission Unit ID: 30
Emission Unit Name: Turbine Circuit Breakers
Emission Unit Description: Three (3) Turbine Circuit Breakers with 30 lb. SF6 Circuits
Equipment ID (SI): EQPT0028

19.1 Process Unit(s)

Process ID: 01
EU ID - PID: 30-01
Process Description: SF6 Releases
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

19.2 Potential Emissions Summary

Parameter	Value	Units	Basis
Circuit Breaker Operating Hours	8760	hr/yr	
Number of Circuit Breakers	3	breakers	
Total SF_6 per Circuit Breaker	30	lb SF_6/breaker	
SF_6 Leak Rate	0.5	%	Maximum allowable leak rate
Annual SF_6 Emissions	2.25E-04	tpy	= 3 breakers * 30 lb SF6/breaker * 1% leak rate/yr / 2,000 lb/ton
SF_6 Global Warming Potential	23,500	lb CO_2e/lb SF_6	GWP, 100-year time horizon from 40 CFR Part 98
Annual CO_2e Emissions	5.29	tpy	= 2.25E-04 tpy SF6 Emissions * 23,500 GWP
Hourly CO_2e Emissions	1.21	lb/hr	= 5.29 tpy x 2,000 lb/ton / 8,760 hr/yr

20. Derivation of Emissions Factors and Calculations for EU 31: Switchyard/Station Circuit Breakers

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 31: Switchyard/Station Circuit Breakers are documented in this section.

Emission Unit ID: 31
Emission Unit Name: Switchyard/Station Circuit Breakers
Emission Unit Description: Twelve (12) Switchyard/Station Circuit Breakers each with 58 lb. SF6 Circuits
Equipment ID (SI): EQPT0029

20.1 Process Unit(s)

Process ID: 01
EU ID - PID: 31-01
Process Description: SF6 Releases
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

20.2 Potential Emissions Summary

Parameter	Value	Units	Basis
Circuit Breaker Operating Hours	8760	hr/yr	
Number of Circuit Breakers	12	breakers	
Total SF_6 per Circuit Breaker	58	lb SF_6/breaker	
SF_6 Leak Rate	0.5	%	Maximum allowable leak rate
Annual SF_6 Emissions	1.74E-03	tpy	= 12 breakers * 58 lb SF6/breaker * 1% leak rate/yr / 2,000 lb/ton
SF_6 Global Warming Potential	23,500	lb CO_2e/lb SF_6	GWP, 100-year time horizon from 40 CFR Part 98
Annual CO_2e Emissions	4.09E+01	tpy	= 1.74E-03 tpy SF6 Emissions * 23,500 GWP
Hourly CO_2e Emissions	9.34	lb/hr	= 40.89 tpy x 2,000 lb/ton / 8,760 hr/yr

21. Derivation of Emissions Factors and Calculations for EU 2n: Indirect Heat Exchanger #2

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 2n: Indirect Heat Exchanger #2 are documented in this section.

Emission Unit ID: 2n
Emission Unit Name: Indirect Heat Exchanger #2
Emission Unit Description: Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas
Equipment ID (SI): COMB004

21.1 Process Unit(s)

> Process ID 02 for coal/wood waste blend combustion is included below for informational purposes only and is not included in the post-modification projected emissions below.

Process ID: 01
EU ID - PID: 2n-01
Process Description: Pulverized Coal
Control Device ID: N/A
Control Device Description: LNBs, DFGD, SCR, PJFF, FuelSolv Treatment
Stack ID: N/A
Stack Description: N/A
Applicable Regulation: 401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:240, 51:250, 51:260, 51:210, 51:220, 51:230, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63(Subpart UUUUU; MATS), 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree
Construction Date: 10/28/1969
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 10100202
SCC Description: External Combustion Boilers - Electric Generation (1-01) - Bituminous/Subbituminous Coal (1-01-002) - Pulverized Coal: Dry Bottom (Bituminous Coal) (1-01-002-02)
SCC Units: Tons Bituminous Coal Burned

Process ID: 02 **NOTE: Please remove process ID 02, as C2 does not have the capability to fire wood waste blend.**

EU ID - PID: 2n-02
Process Description: Coal/Wood Waste Blend

Process ID: 03
EU ID - PID: 2n-03
Process Description: Natural Gas
Control Device ID: N/A
Control Device Description: DFGD (Co-Firing Only), SCR, PJFF, GCP
Stack ID: N/A
Stack Description: N/A
Applicable Regulation: 401 KAR 61:015, 63:002 (MATS; Co-Firing Only), 51:017, 51:160, 52:060, 51:240, 51:250, 51:260, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63 (Subpart UUUUU; MATS for Coal & Co-Firing Only); 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree
Construction Date: 2/1/2028
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code

SCC:	10100601	
SCC Description:	External Combustion Boilers - Electric Generation (1-01) - Natural Gas (1-01-006) - Boilers > 100 Million Btu/hr except Tangential (1-01-006-01)	
SCC Units:	Million Cubic Feet Natural Gas Burned	

21.2 Indirect Heat Exchanger #2 Operational Data and Specifications for C2 and 2n-03 (Post-Modification)

> The proposed modifications to C2 to accommodate co-firing impacts the maximum hourly operating rate for natural gas, as it will take ~ 2.9% more fuel input to generate the maximum MWs generated by the existing steam generator. The operational data and specifications for C2 in the post-modification scenario are provided below.

Max Annual Operating Hours	8,760	hr/yr	
100% Coal Firing Scenario			
Maximum Continuous Rating (MCR)	2,089	MMBtu/hr	Title V permit description
Maximum Total Heat Input Capacity of Burner System	2,364	MMBtu/hr	Heat input required to reach 240 MW gross output from steam generator.
Coal HHV used for engineering design	**12,660**	Btu/lb	Provided by B&M on 2024-1024. Used in A forms and calculations, where necessary.
Coal HHV used for engineering design	**25.32**	MMBtu/ton	= 12,660 Btu/lb * 1 MMBtu/1,000,000 Btu * 2,000 lb/ton
Coal HHV used for AP-42 Section 1.1 EFs	26.00	MMBtu/ton	
Coal HHV used for AP-42 Section 1.1 EFs	13,000	Btu/lb	= 26.00 MMBtu/ton * 1,000,000 Btu/MMBtu / 2,000 lb/ton
Coal HHV used for 40 CFR Part 98 Subpart C EFs	24.93	MMBtu/ton	40 CFR 98, Subpart C, Table C-1 for Bituminous Coal
Allowable Coal Sulfur Content	2.26	% S	Equivalent to permit allowable coal sulfur content of 3.3 lb SO_2/MMBtu
Coal Ash Content	12.00	% ash	DEP 7007A form from U2 retrofit project
Max Annual Coal Combustion at Burner System Capacity	817,881	ton/yr	= 2,364 MMBtu/hr / 12,660 Btu/lb * 1,000,000 Btu/MMBtu / 2,000 lb/ton * 8,760 hr/yr
Max Coal Firing Rate at Burner System Capacity	93.37	ton/hr	= 2,364 MMBtu/hr / 12,660 Btu/lb * 1,000,000 lbs/MMlbs * 1 ton/2,000 lbs
100% NG Firing Scenario			
Post-Modification Maximum Total Heat Input Capacity of Burner System	2,433	MMBtu/hr	Post-modification, heat input required to reach 240 MW gross output from steam generator.
Site-specific NG Heating Value	1,060	Btu/scf	Average for EKPC Inlet Gas
NG HHV used for AP-42 Section 1.4 EF	1,020	Btu/scf	
NG HHV used for 40 CFR Part 98 Subpart C EF	1,026	Btu/scf	
Max NG Firing Rate at 100% capacity	2.30	MMscf/hr	= 2,433 MMBtu/hr / 1,060 Btu/scf

21.3 Derivation and Documentation of Coal Combustion Emission Factors for 2n-01

21.3.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Standard Temperature	68	°F	STP Parameters
	528	°R	
Standard Pressure	1	atm	STP Parameters
Universal Gas Constant	0.7302	cf-atm/(lbmol-°R)	Constant
Molar Volume (at STP)	385.5	scf/lbmol	= 0.7302 cf-atm/(lbmol-°R) * 528 °R / 1.0000 atm
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	

21.3.2 NSR-Regulated Pollutants for Coal Combustion

NO_X			
Uncontrolled NO_X Emission Factor	11	lb/ton	AP-42, Table 1.1-3 for PC, dry bottom, wall-fired, bituminous, Pre-NSPS
	0.423	lb/MMBtu	Used AP-42 heat content for conversion
Controlled, Allowable NO_X Emission Factor	0.080	lb/MMBtu	CD entered September 24, 2007, paragraph 53, 30-day rolling average
NO_X Control Efficiency for SCR (Uncont. AP-42 vs. Allowable)	81.09	%	Calculated from uncontrolled vs. allowable
Controlled NO_X Emission Factor	2.080	lb/ton	= 11 lb/ton Uncontrolled NOX Emission Factor * (100% - 81.09%)
	0.080	**lb/MMBtu**	2.1 lb/ton / 26.00 MMBtu/ton (AP-42) = 0.080 lb/MMBtu; Selected for PTE calc.
CO			
Uncontrolled CO Emission Factor	0.5	lb/ton	AP-42, Table 1.1-3 for PC, dry bottom, wall-fired, bituminous, Pre-NSPS
	0.019	lb/MMBtu	0.5 lb/ton / 26.00 MMBtu/ton (AP-42) = 0.0192 lb/MMBtu
VOC			
Uncontrolled VOC Emission Factor	0.060	lb/ton	AP-42, Table 1.1-19 for PC-fired, dry bottom, wall fired
	0.0023	lb/MMBtu	0.060 lb/ton / 26.00 MMBtu/ton (AP-42) = 0.0023 lb/MMBtu
SO_2			
AP-42 Factor for SO_2 based on sulfur content:	38 S	lb/ton	AP-42 Table 1.1-3 (S is sulfur content in %) for PC, dry bottom, wall-fired, bituminous, Pre-NSPS
Uncontrolled SO_2 Emission Factor	85.88	lb/ton	= 38 * 2.26% Sulfur
	3.30	lb/MMBtu	Used AP-42 factor of 26.0 MMBtu/ton of coal versus applying a site-specific value. As a result, 85.9 lb/ton / 26.00 MMBtu/ton = 3.30 lb/MMBtu
Controlled SO_2 Emission Factor in Baseline Period from CEMS	0.036	lb/MMBtu	From CEMs data
SO_2 Control Efficiency (AP-42 Uncont. vs. CEMS)	98.92	%	Calculated from uncontrolled vs. CEMS
Controlled SO_2 Emission Factor	0.927	lb/ton	= 85.88 lb/ton Uncontrolled SO2 Emission Factor * (100% - 98.92%)
	0.036	lb/MMBtu	0.927 lb/ton / 26.00 MMBtu/ton (AP-42) = 0.036 lb/MMBtu

Allowable Uncontrolled SO_2 Emission Factor	3.3 lb/MMBtu	401 KAR 61:015, 401 KAR 51:010 and 401 KAR 53:010
Allowable DFGD SO_2 Control Efficiency	95.0% % CE (at least)	30-day rolling average; Pursuant to 401 KAR 51:010 and 401 KAR 53:010
Allowable Controlled SO_2 Emission Factor	0.165 lb/MMBtu	= 3.30 lb/MMBtu Allowable Uncontrolled SO2 Emission Factor * (100% - 0.95%)
	or	
	0.100 lb/MMBtu	30-day rolling average limit from 401 KAR 51:010 and 401 KAR 53:010; More stringent than calculated allowable and used in PTE calc.
SO_2 Control Efficiency (AP-42 Uncont. vs. Allowable Cont.)	**96.97 %**	= (3.30 lb/MMBtu Uncontrolled SO2 Emission Factor - 0.10 lb/MMBtu Allowable Controlled SO2 Emission Factor)/3.30 lb/MMBtu Uncontrolled SO2 Emission Factor * 100

H_2SO_4

Molecular Weight of SO_3	80.06 lb/lbmol	
Molecular Weight of H_2SO_4	98.08 lb/lbmol	
SO_2 to SO_3 Conversion	100%	
SO_3 to H_2SO_4 Conversion	0.148%	Conservative estimate based on chemical reactions promoted within control train
Uncontrolled Emission Factor of H_2SO_4	0.1270 lb/ton	= 85.880 lb SO2/ton * 100% SO2 to SO3 Conversion * 0.148% SO3 to H2SO4 Conversion
	0.0050 lb/MMBtu	= 0.1270 lb H2SO4/ton / 25.32 MMBtu/ton (site-specific)

Filterable PM

AP-42 Factor for PM-Filt. based on ash content:	10 A lb/ton	AP-42 Table 1.1-4 (A is ash content in %) for PC-fired, dry bottom, wall-fired
Uncontrolled PM-Filt. Emission Factor	120.0 lb/ton	= 10 * 12.00% Ash
	4.615 lb/MMBtu	120.0 lb/ton / 26.00 MMBtu/ton = 4.615 lb/MMBtu
PM-Filt. Control Efficiency	99.87 %	Calculated from stack test vs Uncontrolled
Controlled PM-Filt. Emission Factor	0.156 lb/ton	= 120.0 Uncontrolled PM-Filt. Emission Factor * (100% - 99.87%)
	0.006 lb/MMBtu	Annual PM emission test conducted 4/28/2023
Controlled, Allowable PM-Filt. Emission Factors	0.230 lb/MMBtu	Allowable per 401 KAR 61:015
	0.030 lb/MMBtu	CD entered September 24, 2007, paragraph 84
	0.030 lb/MMBtu	Kentucky BART SIP
	0.010 lb/MMBtu	Proposed BACT for natural gas and coal co-firing scenario
PM-Filt. Control Efficiency (AP-42 Uncont. Vs. Allowable Cont.)	**99.78** %	= (4.62 lb/MMBtu Uncontrolled PM-Filt. Emission Factor - 0.01 lb/MMBtu Controlled, Allowable PM-Filt. Emission Factors)/4.62 lb/MMBtu Uncontrolled PM-Filt. Emission Factor * 100; Needed to meet BACT

Filterable PM_{10}

Uncontrolled PM_{10}-Filt. Emission Factor	110.4 lb/ton	= 120.0 lb/ton Filterable PM * 92% Cumulative Mass Fraction ≤ 10 microns from AP-42 Tbl 1.1-6 for dry bottom boilers burning pulverized bituminous or subbituminous coal equipped with baghouses
	4.246 lb/MMBtu	= 110.4 lb/ton / 26.00 MMBtu/ton (AP-42)
Control PM_{10}-Filt. Efficiency	99.78 %	Assume same CE as PM-Filt.
Controlled PM_{10}-Filt. Emission Factor	0.239 lb/ton	= 110.4 Uncontrolled PM10-Filt. Emission Factor * (100% - 99.78%)
	0.009 lb/MMBtu	= 0.239 lb/ton / 26.00 MMBtu/ton

Filterable $PM_{2.5}$

Uncontrolled $PM_{2.5}$-Filt. Emission Factor	63.6 lb/ton	= 120.0 lb/ton Filterable PM * 53% Cumulative Mass Fraction ≤ 10 microns from AP-42 Tbl 1.1-6 for dry bottom boilers burning pulverized bituminous or subbituminous coal equipped with baghouses
	2.446 lb/MMBtu	= 63.6 lb/ton / 26.00 MMBtu/ton (AP-42)
Control $PM_{2.5}$-Filt. Efficiency	99.78 %	Assume same CE as PM-Fil
Controlled $PM_{2.5}$-Filt. Emission Factor	0.138 lb/ton	= 63.6 Uncontrolled PM2.5-Filt. Emission Factor * (100% - 99.78%)
	0.005 lb/MMBtu	= 0.138 lb/ton / 26.00 MMBtu/ton

Condensable PM

> Conservatively assuming all condensable species are less than 2.5 microns in diameter.

Controlled PM-Cond. Emission Factor	0.02 lb/MMBtu	AP-42 Table 1.1-5 for all PC-fired boilers & all PM controls combined w/ FGD controls
Controlled PM-Cond. Emission Factor	0.520 lb/ton	= 0.02 lb/MMBtu x 26 MMBtu/ton
Assumed Control PM-Cond. Efficiency	0 %	Uncontrolled PM-Cond. emission factor for PC-fired boilers not available in AP-42, so conservatively assume no PM-Cond. control efficiency
Uncontrolled PM-Cond. Emission Factor	0.52 lb/ton	= 0.520 lb/ton Controlled PM-Cond. Emission Factor / (100% - 0.00% control efficiency)

Total PM_{10}

Controlled PM_{10}-Total Emission Factor	0.029 lb/MMBtu	Sum of PM_{10}-Filt. & PM-Cond. emission factors

Total $PM_{2.5}$

Controlled $PM_{2.5}$-Total Emission Factor	0.025 lb/MMBtu	Sum of $PM_{2.5}$-Filt. & PM-Cond. emission factors

Greenhouse Gases

> Emission factors for GHGs are based on Subpart C of EPA's Greenhouse Gas Reporting Program (GHGRP, 40 CFR 98 Subpart C Table C-1).

> The global warming multiplying factors for CH_4 and N_2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO_2e emissions.

CO_2			
Uncontrolled CO_2 Emission Factor	93.28	kg/MMBtu	40 CFR 98, Subpart C, Table C-1 for Bituminous Coal
Uncontrolled CO_2 Emission Factor	5,127	lb/ton	= 93.28 kg/MMBtu * 2.205 lb/kg * 24.93 MMBtu/ton
	205.6	**lb/MMBtu**	Used for PAE and PTE calc.
CO_2 Emission Factor from CEMS Data	205.2	lb/MMBtu	Average over baseline from CEMs data; Approximately equivalent to 40 CFR 98 Table C-1 CO_2 emission factor, so use this GHGRP factor for PAE/PTE calc.
CH_4			
Uncontrolled CH_4 Emission Factor	0.011	kg/MMBtu	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)
Uncontrolled CH_4 Emission Factor	0.60	lb/ton	= 0.011 kg/MMBtu * 2.205 lb/kg * 24.93 MMBtu/ton
	0.024	lb/MMBtu	
N_2O			
Uncontrolled N_2O Emission Factor	0.0016	kg/MMBtu	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)
Uncontrolled N_2O Emission Factor	0.088	lb/ton	= 0.0016 kg/MMBtu * 2.205 lb/kg * 24.93 MMBtu/ton
	0.0035	lb/MMBtu	
CO_2e			
Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.			
CO_2	1		
CH_4	28		89 FR 42218, May 14, 2024
N_2O	265		89 FR 42218, May 14, 2024
Uncontrolled GHG (CO_2e) Emission Factor	5,167	lb/ton	(CO_2 EF) + (CH_4 EF * 28 CH_4 GWP) + (N_2O EF * 265 N_2O GWP)
	207.3	lb/MMBtu	

21.3.3 Ammonia (from Ammonia Slip in SCR) for Coal Combustion

NH_3

NH_3 Concentration in Stack Exhaust	6 ppmvd @ 15% O_2	Average of typical permitted ammonia slip, per EPA Air Pollution Control Technology Fact Sheet for SCR
Molecular Weight of NH_3	17.04 lb/lbmol	
Oxygen based F-Factor	9,780 dscf/MMBtu	RM Method 19 determination of Fd factor for bituminous coal combustion can use a default value of 9,780, or use equations 19-13 through 19.15. EKPC chose to use the default Fd factor from RM 19.
Uncontrolled NH_3 Emission Factor	0.239 lb/ton	= 1 atm * 17.04 lb/lbmol / (0.7302 ft3*atm/lbmol*R) / (528 R) * 6 ppmvd @ 15% O2 / 1,000,000 * 9,780 dscf/MMBtu * (20.9)/(20.9-15) O2% correction * 26.00 MMBtu/ton
	0.0094 lb/MMBtu	= 0.239 lb/ton / 25.32 MMBtu/ton
Uncontrolled NH_3 Emission Rate	22.3 lb/hr	= 0.239 lb/ton / 93.37 ton/hr at max hourly

21.3.4 Hazardous Air Pollutants for Coal Combustion

> Uncontrolled emission factors for select HAP emissions from bituminous coal-fired boilers published in AP-42, Section 1.1 are used to estimate potential emissions.

Pollutant	CAS No.	Uncontrolled Emission Factor (lb/ton)	Uncontrolled Emission Factor (lb/MMBtu)	Control Efficiency (%)[1,2]	Controlled Emission Factor (lb/ton)	Controlled Emission Factor (lb/MMBtu)	Basis
Organic Compounds							
Benzene	71-43-2	1.30E-03	5.00E-05	na	1.30E-03	5.00E-05	AP-42 Tab 1.1-14
Cyanide Compounds	--	2.50E-03	9.62E-05	na	2.50E-03	9.62E-05	AP-42 Tab 1.1-14
Formaldehyde	50-00-0	2.40E-04	9.23E-06	na	2.40E-04	9.23E-06	AP-42 Tab 1.1-14
Hexane	110-54-3	6.70E-05	2.58E-06	na	6.70E-05	2.58E-06	AP-42 Tab 1.1-14
Hydrogen Chloride	7647-01-0	1.2	4.62E-02	98.12%	2.26E-02	8.68E-04	AP-42 Tab 1.1-14
Hydrogen Fluoride	7664-39-3	0.15	5.77E-03	98.12%	2.82E-03	1.08E-04	AP-42 Tab 1.1-14
Toluene	108-88-3	2.40E-04	9.23E-06	na	2.40E-04	9.23E-06	AP-42 Tab 1.1-14
Metallic Compounds							
Arsenic	7440-38-2	1.78E-02	6.84E-04	99.74%	4.62E-05	1.78E-06	AP-42 Tab 1.1-17
Cadmium	7440-43-9	1.15E-03	4.44E-05	99.74%	3.00E-06	1.15E-07	AP-42 Tab 1.1-17
Chromium	7440-47-3	3.67E-02	1.41E-03	99.74%	9.53E-05	3.67E-06	AP-42 Tab 1.1-17
Lead	7439-92-1	1.32E-02	5.07E-04	99.74%	3.43E-05	1.32E-06	AP-42 Tab 1.1-17
Manganese	7439-96-5	4.17E-02	1.60E-03	99.74%	1.08E-04	4.17E-06	AP-42 Tab 1.1-17
Mercury	7439-97-6	4.16E-04	1.60E-05	99.74%	1.08E-06	4.16E-08	AP-42 Tab 1.1-17
Nickel	7440-02-0	3.02E-02	1.16E-03	99.74%	7.84E-05	3.02E-06	AP-42 Tab 1.1-17

[1] Control efficiency for HCl and HF from FGD system per 2022 DAQ-accepted Web Survey.

[2] Control efficiency for metallic HAP from fabric filter per 2022 DAQ-accepted Web Survey

21.3.5 Emission Factor Summary for Coal Combustion

Pollutant	Uncontrolled Potential Emission Factor (lb/MMBtu)	Control Efficiency (%)	Controlled Potential Emission Factor (lb/MMBtu)	Basis
Regulated NSR Pollutants				
NO_X	0.423	81.1	0.0800	AP-42, Table 1.1-3 for PC, dry bottom, wall-fired, bituminous, Pre-NSPS uncont. NOX EF, control afforded by SCR to achieve allowable NOX
CO	0.019	na	0.019	AP-42, Table 1.1-3 for PC, dry bottom, wall-fired, bituminous, Pre-NSPS
VOC	0.0023	na	0.0023	AP-42, Table 1.1-19 for PC-fired, dry bottom, wall fired
PM-FIL	4.6154	99.78	0.0100	AP-42 Table 1.1-4 (A is ash content in %) for PC-fired, dry bottom, wall-fired uncont. PM-Filt. EF, control afforded by PJFF to achieve allowable PM-Filt.
PM_{10}-FIL	4.2462	99.78	0.0092	= 120.0 lb/ton Filterable PM * 92% Cumulative Mass Fraction ≤ 10 microns from AP-42 Tbl 1.1-6 for dry bottom boilers burning pulverized bituminous or subbituminous coal equipped with baghouses for uncont. PM10-Filt. EF; Assume PM-Filt. control efficiency applies to PM10-Filt.
$PM_{2.5}$-FIL	2.4462	99.78	0.0053	= 120.0 lb/ton Filterable PM * 53% Cumulative Mass Fraction ≤ 10 microns from AP-42 Tbl 1.1-6 for dry bottom boilers burning pulverized bituminous or subbituminous coal equipped with baghouses for uncont. PM2.5-Filt. EF; Assume PM-Filt. control efficiency applies to PM2.5-Filt.
PM-CON	0.0200	0.00	0.0200	AP-42 Table 1.1-5 for all PC-fired boilers & all PM controls combined w/ FGD controls
PM_{10}-TOT	4.2662	99.32	0.0292	PM_{10}-Filt + CPM, control afforded by PJFF
$PM_{2.5}$-TOT	2.4662	98.97	0.0253	$PM_{2.5}$-Filt + CPM, control afforded by PJFF
PM-TOT	4.6354	99.35	0.0300	PM-Filt + CPM, control afforded by PJFF
SO_2	3.30	96.97	0.1000	AP-42 Table 1.1-3 (S is sulfur content in %) for PC, dry bottom, wall-fired, bituminous, Pre-NSPS uncont. SO2 EF, control afforded by DFGD to achieve allowable SO2
H_2SO_4	5.02E-03	na	5.02E-03	Conversion in boiler & SCR w/ reduction by NH3 slip and F-factors for APH and WFGD+BH
Lead	5.07E-04	99.74	1.32E-06	AP-42 Tab 1.1-17
CO_2	205.65	na	205.65	40 CFR 98, Subpart C, Table C-1 for Bituminous Coal
CH_4	0.0243	na	0.0243	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)
N_2O	0.0035	na	0.0035	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)
CO_2e	207.26	na	207.26	(CO2 EF) + (CH4 EF * 28 CH4 GWP) + (N2O EF * 265 N2O GWP)
Toxics/HAP Summary				
NH_3	9.44E-03	na	9.44E-03	Avg of typical ammonia slip of 6 ppmvd @6% O2 and Method 19
Total HAP	1.16E-03	na	1.16E-03	Sum of HAPs
Organic HAP Compounds				
Benzene	5.00E-05	na	5.00E-05	AP-42 Tab 1.1-14
Cyanide Compounds	9.62E-05	na	9.62E-05	AP-42 Tab 1.1-14
Formaldehyde	9.23E-06	na	9.23E-06	AP-42 Tab 1.1-14
Hexane	2.58E-06	na	2.58E-06	AP-42 Tab 1.1-14
Hydrogen Chloride	4.62E-02	98.12	8.68E-04	AP-42 Tab 1.1-14
Hydrogen Fluoride	5.77E-03	98.12	1.08E-04	AP-42 Tab 1.1-14
Toluene	9.23E-06	na	9.23E-06	AP-42 Tab 1.1-14

Metallic HAP Compounds				
Arsenic	6.84E-04	99.74	1.78E-06	AP-42 Tab 1.1-17
Cadmium	4.44E-05	99.74	1.15E-07	AP-42 Tab 1.1-17
Chromium	1.41E-03	99.74	3.67E-06	AP-42 Tab 1.1-17
Manganese	1.60E-03	99.74	4.17E-06	AP-42 Tab 1.1-17
Mercury	1.60E-05	99.74	4.16E-08	AP-42 Tab 1.1-17
Nickel	1.16E-03	99.74	3.02E-06	AP-42 Tab 1.1-17

21.4 Derivation and Documentation of Natural Gas Combustion Emission Factors for 2n-03

21.4.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Standard Temperature	68	°F	STP Parameters
	528	°R	
Standard Pressure	1	atm	STP Parameters
Universal Gas Constant	0.7302	cf-atm/(lbmol-°R)	Constant
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm * 0.7302 cf-atm/(lbmol-°R)
Mass Conversion	7,000	gr/lb	
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO_2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO_2	64.07	lb SO_2/lbmol	
Molecular Weight of H_2SO_4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/100 scf	Assumed max sulfur content for EKPC inlet NG

21.4.2 NSR-Regulated Pollutant Uncontrolled Emission Factors for Natural Gas Combustion

Parameter	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
Uncontrolled NO_X from retractable spud burner	0.275	280.0	AP-42 Table 1.4-1 Large Wall-Fired Boilers (>100 MMBtu/hr), Uncontrolled (Pre-NSPS); NOX emissions performance of retractable spud burners as a retrofit to existing coal burners in Unit 2 is expected to be approximately equivalent to this AP-42 Table 1.4-1 burner type NO_X emission factor basis
NO_x Control Efficiency (%)	70.86%	70.86%	Back-calculated from controlled and uncontrolled NO_X emissions estimates; Also, supported by expected SCR NO_X emissions performance design basis of converted unit
Controlled NO_X	0.080	81.6	Proposed BACT for NG and coal co-firing scenario
Uncontrolled CO	0.120	127.2	Proposed BACT for natural gas and coal co-firing scenario.
Uncontrolled VOC	0.0054	5.5	AP-42 Section 1.4 Table 1.4-2
Uncontrolled PM-FIL	0.0019	1.90	AP-42 Section 1.4 Table 1.4-2
Uncontrolled PM_{10}-FIL	0.0019	1.90	Assumes PM-FIL=PM_{10}-FIL=$PM_{2.5}$-FIL
Uncontrolled $PM_{2.5}$-FIL	0.0019	1.90	Assumes PM-FIL=PM_{10}-FIL=$PM_{2.5}$-FIL
Uncontrolled PM-CON	0.0015	1.57	AP-42 Section 1.4 Table 1.4-2, difference between EPA Speciate database for total PM and AP-42 for filterable PM.
Uncontrolled PM-TOT	0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
Uncontrolled PM_{10}-TOT	0.0034	3.47	= PM_{10}-FIL + PM-CON
Uncontrolled $PM_{2.5}$-TOT	0.0034	3.47	= $PM_{2.5}$-FIL + PM-CON
Uncontrolled SO_2	0.0013	1.427	= 0.5 gr/Ccf / 7,000 gr/lb * 64.07 lb SO2/lbmol / 32.07 lb S/lbmol * 10,000 Ccf/MMscf
Uncontrolled H_2SO_4	1.03E-05	0.011	1.531% conversion of SO_2 to H_2SO_4 and 0.5 F2 for Air Preheater
Uncontrolled Lead	4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2

Uncontrolled CO_2	116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
Uncontrolled CH_4	0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
Uncontrolled N_2O	0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
Uncontrolled CO_2e	117.10	120,142	= CO2 EF * 1 CO2 GWP + CH4 EF * 28 CH4 GWP + N2O EF * 265 N2O GWP

21.4.3 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf

Pollutant	CAS No.	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Basis
Speciated Organic Compounds (AP-42, Table 1.4-3)				
Benzene	71-43-2	2.1E-03	1.98E-06	AP-42 Table 1.4-3
Dichlorobenzene	25321-22-6	1.2E-03	1.13E-06	AP-42 Table 1.4-3
Formaldehyde	50-00-0	7.5E-02	7.08E-05	AP-42 Table 1.4-3
Hexane	110-54-3	1.80	1.70E-03	AP-42 Table 1.4-3
Naphthalene	91-20-3	6.1E-04	5.75E-07	AP-42 Table 1.4-3
Toluene	108-88-3	3.4E-03	3.21E-06	AP-42 Table 1.4-3
Metals (AP-42, Table 1.4-4)				
Arsenic	7440-38-2	2.0E-04	1.89E-07	AP-42 Table 1.4-4
Cadmium	7440-43-9	1.1E-03	1.04E-06	AP-42 Table 1.4-4
Chromium	7440-47-3	1.4E-03	1.32E-06	AP-42 Table 1.4-4
Manganese	7439-96-5	3.8E-04	3.58E-07	AP-42 Table 1.4-4
Mercury	7439-97-6	2.6E-04	2.45E-07	AP-42 Table 1.4-4
Nickel	7440-02-0	2.1E-03	1.98E-06	AP-42 Table 1.4-4
Total HAP		1.89	1.78E-03	Sum of HAP above

21.4.4 Emission Factor Summary for Natural Gas Combustion

Pollutant	Uncontrolled Emission Factor (lb/MMBtu)	Control Efficiency (%)	Controlled Emission Factor (lb/MMBtu)	Basis
Regulated NSR Pollutants				
NO_X	0.275	70.86	0.080	AP-42 Table 1.4-1 Large Wall-Fired Boilers (>100 MMBtu/hr), Uncontrolled (Pre-NSPS); Adjusted, CE% to represent the 0.08 lb/MMBtu BACT. EKPC will use SCR during all co-firing and NG only scenarios.
CO	0.120	na	0.120	Proposed BACT for natural gas and coal co-firing scenario.
VOC	5.39E-03	na	5.39E-03	AP-42 Section 1.4 Table 1.4-2
PM-FIL	1.86E-03	na	1.86E-03	AP-42 Section 1.4 Table 1.4-2 for uncontrolled emission factor; Assumes PJFF achieves negligible control for NG Portion of PM-FIL emissions due to small particle size and low inlet emissions
PM_{10}-FIL	1.86E-03	na	1.86E-03	Assumes PM-FIL=PM10-FIL=PM2.5-FIL
$PM_{2.5}$-FIL	1.86E-03	na	1.86E-03	Assumes PM-FIL=PM10-FIL=PM2.5-FIL
PM-CON	1.54E-03	na	1.54E-03	AP-42 Section 1.4 Table 1.4-2, difference between EPA Speciate database for total PM and AP-42 for filterable PM.
PM-TOT	3.40E-03	na	3.40E-03	AP-42 Table 1.4-2 + EPA Speciate Database
PM_{10}-TOT	3.40E-03	na	3.40E-03	= PM10-FIL + PM-CON
$PM_{2.5}$-TOT	3.40E-03	na	3.40E-03	= PM2.5-FIL + PM-CON
SO_2	1.35E-03	na	1.35E-03	Pipeline spec conversion; Conservatively assumes DFGD does not offer any appreciable SO_2 control for NG portion of SO_2 emissions due to low concentration/inlet loading during co-firing, and DFGD will not be supplied with sorbent during NG only operation offering minimal/negligible SO_2 emissions control
H_2SO_4	1.03E-05	na	1.03E-05	1.531% conversion of SO2 to H2SO4 and 0.5 F2 for Air Preheater
Lead	4.90E-07	na	4.90E-07	AP-42, Section 1.4, Table 1.4-2
CO_2	116.98	na	116.98	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH_4	2.20E-03	na	2.20E-03	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N_2O	2.20E-04	na	2.20E-04	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO_2e	117.10	na	117.10	= CO2 EF * 1 CO2 GWP + CH4 EF * 28 CH4 GWP + N2O EF * 265 N2O GWP
Toxics/HAP Summary				
Total HAP	1.78E-03	na	1.78E-03	Sum of HAPs
Organic HAP Compounds				
Benzene	2.0E-06	na	2.0E-06	AP-42 Table 1.4-3
Dichlorobenzene	1.1E-06	na	1.1E-06	AP-42 Table 1.4-3
Formaldehyde	7.1E-05	na	7.1E-05	AP-42 Table 1.4-3
Hexane	1.7E-03	na	1.7E-03	AP-42 Table 1.4-3
Naphthalene	5.8E-07	na	5.8E-07	AP-42 Table 1.4-3
Toluene	3.2E-06	na	3.2E-06	AP-42 Table 1.4-3
Metallic HAP Compounds				
Arsenic	1.9E-07	na	1.9E-07	AP-42 Table 1.4-4
Cadmium	1.0E-06	na	1.0E-06	AP-42 Table 1.4-4
Chromium	1.3E-06	na	1.3E-06	AP-42 Table 1.4-4
Manganese	3.6E-07	na	3.6E-07	AP-42 Table 1.4-4
Mercury	2.5E-07	na	2.5E-07	AP-42 Table 1.4-4
Nickel	2.0E-06	na	2.0E-06	AP-42 Table 1.4-4

21.5 Project Emissions Increase

21.5.1 Projected Actual Emissions for C2

- Per 401 KAR 51:001, Section 1(199)(b)2, a source may elect to use the emission unit's potential to emit, in tons per year, to determine projected actual emissions (PAE). With this application, EKPC is proposing a synthetic minor SO_2 emissions limit, which sets the emissions increase from the project to 39 tpy. Therefore, projected actual emissions are based on either of the following scenarios: Scenario 1) Maximum allowable coal throughput (equivalent to annual heat input in baseline period) with additional co-firing of natural gas up to the synthetic minor limit, or Scenario 2) 100% NG firing at the maximum heat input capacity with an overall SO_2 emissions decrease. Due to uncertainty in future fuel supply and pricing and Cooper Station dispatch schedules, EKPC has determined projected actual emissions using the worst-case heat input for C2 and the associated maximum emissions from the two scenarios on a pollutant-by-pollutant basis rather than pursuing a less conservative forecast of the maximum actual annual emission rate that would be permissible under the regulatory definition of PAE.
- Actual coal emission factors for PM and SO_2 are derived below based on stack testing and CEMS data, respectively. Use of potential/allowable emission factors for PM and SO_2 emissions from coal usage in the PAE calculation would result in a non-representative PAE estimate that would show an arbitrary project emissions increase relative to the baseline actual emissions which are obtained directly from these same CEMS/stack testing data.

Parameter	Scenario 1 Co-Fire	Scenario 2 100% NG	
Coal heat input (MMBtu/yr)	**4,192,207**	0	Note: For coal heat input, see 22.3 Unit 2 Boiler: SO_2 BAE
NG heat input (MMBtu/yr)	8,391,723	21,314,131	
Total heat input (MMBtu/yr)	12,583,930	21,314,131	
Annual Capacity (MMBtu/yr)	21,112,418	21,314,131	
Capacity Utilization (%)	60%	100%	

Pollutant	Coal Emission Factor (lb/MMBtu)	NG Emission Factor (lb/MMBtu)	PAE (Scenario 1) (tpy)	PAE (Scenario 2) (tpy)
NO_X	0.080	0.080	503.37	852.57
CO	0.0192	0.120	543.81	1278.85
VOC	0.0023	5.39E-03	27.46	57.46
PM-FIL	0.0045*	1.86E-03	17.25	19.85
PM_{10}-FIL	0.0041	1.86E-03	16.49	19.85
$PM_{2.5}$-FIL	0.0024	1.86E-03	12.82	19.85
PM-CON	0.0200	1.54E-03	48.38	16.40
PM_{10}-TOT	0.0241	3.40E-03	64.87	36.25
$PM_{2.5}$-TOT	0.0224	3.40E-03	61.20	36.25
SO_2	0.0356**	1.35E-03	80.36	14.35
H_2SO_4	5.02E-03	1.03E-05	10.56	0.11
Lead	1.32E-06	4.90E-07	4.82E-03	5.22E-03
CO_2	205.6	117.0	921,878	1,246,635
CH_4	0.0243	2.20E-03	60	23.49
N_2O	0.0035	2.20E-04	8	2.35
CO_2e	207.26	117.10	925,765	1,247,915

* Average of 6/6/2022 and 4/28/2023 stack tests using Method 5. See Section 22.7.1.

** See 22.3 Unit 2 Boiler: SO2 Baseline Actual Emissions

21.5.2 Baseline Actual Emissions for C2

> Baseline actual emissions are those occurring during a consecutive 24-month period within the 5-year period immediately preceding the construction date for the planned C2 modifications.
> Detailed baseline actual emission calculations are provided in Section 22.

Pollutant	Baseline Period	BAE (tpy)
NO_X	June 2022 - May 2024	94.72
CO	June 2022 - May 2024	40.47
VOC	June 2022 - May 2024	4.83
PM-FIL	June 2022 - May 2024	8.85
PM_{10}-FIL	June 2022 - May 2024	8.14
$PM_{2.5}$-FIL	June 2022 - May 2024	4.69
PM-CON	June 2022 - May 2024	41.83
PM_{10}-TOT	June 2022 - May 2024	49.97
$PM_{2.5}$-TOT	June 2022 - May 2024	46.52
SO_2	June 2022 - May 2024	74.71
H_2SO_4	June 2022 - April 2024	0.45
Lead	June 2022 - May 2024	2.75E-03
CO_2	June 2022 - May 2024	428,258
CH_4	June 2022 - May 2024	50.67
N_2O	June 2022 - May 2024	7.37
CO_2e	June 2022 - May 2024	431,631

21.5.3 Project Emissions Increase

> In accordance with 401 KAR 51:017 Section 1(4)(a) and (b), the emissions increase for an existing emission unit is the difference between the projected actual emissions and the baseline actual emissions.

PAE Scenario 1 (Co-fire)

Pollutant	PAE (tpy)	BAE (tpy)	C2 Emissions Increase (PAE - BAE) (tpy)
NO_X	503.37	94.72	408.65
CO	543.81	40.47	503.34
VOC	27.46	4.83	22.63
PM-FIL	17.25	8.85	8.40
PM_{10}-FIL	16.49	8.14	8.35
$PM_{2.5}$-FIL	12.82	4.69	8.12
PM-CON	48.38	41.83	6.55
PM_{10}-TOT	64.87	49.97	14.90
$PM_{2.5}$-TOT	61.20	46.52	14.68
SO_2	80.36	74.71	5.65
H_2SO_4	10.56	0.45	10.11
Lead	4.82E-03	2.75E-03	2.07E-03
CO_2	921,878	428,258	493,620
CH_4	60.08	50.67	9.41
N_2O	8.32	7.37	0.94
CO_2e	925,765	431,631	494,134

PAE Scenario 2 (100% NG)

Pollutant	PAE (tpy)	BAE (tpy)	C2 Emissions Increase (PAE - BAE) (tpy)
NO_X	852.57	94.72	757.85
CO	1278.85	40.47	1238.38
VOC	57.46	4.83	52.64
PM-FIL	19.85	8.85	11.00
PM_{10}-FIL	19.85	8.14	11.71
$PM_{2.5}$-FIL	19.85	4.69	15.16
PM-CON	16.40	41.83	-25.42
PM_{10}-TOT	36.25	49.97	-13.72
$PM_{2.5}$-TOT	36.25	46.52	-10.26
SO_2	14.35	74.71	-60.36
H_2SO_4	0.11	0.45	-0.34
Lead	5.22E-03	2.75E-03	2.47E-03
CO_2	1,246,635	428,258	818,376
CH_4	23.49	50.67	-27.18
N_2O	2.35	7.37	-5.02
CO_2e	1,247,915	431,631	816,284

Pollutant	Worst-Case C2 PEI (tpy)	Basis
NO_X	757.85	Scenario 2
CO	1238.38	Scenario 2
VOC	52.64	Scenario 2
PM-FIL	11.00	Scenario 2
PM_{10}-FIL	11.71	Scenario 2
$PM_{2.5}$-FIL	15.16	Scenario 2
PM-CON	6.55	Scenario 1
PM_{10}-TOT	14.90	Scenario 1
$PM_{2.5}$-TOT	14.68	Scenario 1
SO_2	5.65	Scenario 1
H_2SO_4	10.11	Scenario 1
Lead	2.47E-03	Scenario 2
CO_2	818,376	Scenario 2
CH_4	9.41	Scenario 1
N_2O	0.94	Scenario 1
CO_2e	816,284	Scenario 2

22. Detailed Baseline Actual Emissions for C2

> The project covered by this permit application encompasses the planned installation of a new CCGT unit, as well as an unrelated modification of C2 to co-fire coal with natural gas or by itself.

> The new CCTC unit is targeted to commence operation on April 1, 2028 following a 37-month construction and commissioning phase. Accordingly, the anticipated start of construction for the project is March 1, 2030.

> Pursuant to 40 CFR 52.21(b)(48)(i), for any existing electric utility steam generating unit, baseline actual emissions are the average rate in tons per year at which the unit actually emitted a pollutant during any consecutive 24-month period selected by the owner/operator within the 5-year period immediately preceding the time the owner/operator begins actual construction of the project. Thus, for this project, the earliest baseline period available is the 24-month period ending February 2022 (i.e., March 2020 to February 2022).

> A separate 24-month period may be selected for defining baseline actual emissions for each pollutant. The selected baseline period used along with documentation of the baseline actual emissions (and thus the equivalent emission reductions for the project) are provided in the following sub-sections for each relevant regulated NSR polluted emitted by the Unit 2 boiler.

Emission Unit ID:	2n
Emission Unit Name:	Indirect Heat Exchanger #2
Emission Unit Description:	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas
Equipment ID (SI):	COMB004

22.1 Unit 2 Process Unit(s)

Process ID:	01
EU ID - PID:	2n-01
Process Description:	Pulverized Coal
Control Device ID:	N/A
Control Device Description:	LNBs, DFGD, SCR, PJFF, FuelSolv Treatment
Stack ID:	N/A
Stack Description:	N/A
Applicable Regulation:	401 KAR 61:015, 63:002 (MATS), 51:160, 52:060, 51:240, 51:250, 51:260, 51:210, 51:220, 51:230, 40 CFR 52 Subpart S (BART SIP), 40 CFR 64 (CAM), 40 CFR 75 (CEMS), 40 CFR 63(Subpart UUUUU; MATS), 40 CFR 97 (AAAAA, CCCCC, & EEEEE), Consent Decree
Construction Date:	10/28/1969
Fugitive Emissions?	No
Count Emissions for PTE?	Yes

Source Classification Code

SCC:	10100202
SCC Description:	External Combustion Boilers - Electric Generation (1-01) - Bituminous/Subbituminous Coal (1-01-002) - Pulverized Coal: Dry Bottom (Bituminous Coal) (1-01-002-02)
SCC Units:	Tons Bituminous Coal Burned

22.2 Unit 2 Boiler: NOX Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of NO_X.

> Unit 2 utilizes SCR for NO_X control. Unit 1 has no NO_X control. Because the CEMS data is from a common stack for Unit 1 and Unit 2, CEMS emissions needed to be split between the two units using inlet CEMS data. The Unit 2 baseline NO_X emissions data presented below reflects this splitting up of the common stack CEMS data and generally produces a combined Unit 1 and 2 NO_X emission rate on a monthly basis which closely matches the reported CEMS data via the Clean Air Markets Program Data (CAMPD). Additional supporting documentation on an hour-by-hour period within the selected based period is available upon request.

Month	Combined Heat Input (MMBtu)	NO_X Emissions (tons)	Operating Time (hrs)	NO_X Emissions (lb/hr)
6/2022	820,421	18.2	534.5	68.1
7/2022	899,676	19.6	606.2	64.8
8/2022	581,515	13.4	394.8	67.8
9/2022	323,500	4.3	214.9	40.3
10/2022	0	0.0	0.0	--
11/2022	0	0.0	0.0	--
12/2022	598	0.0	11.6	-- (Exclude)
1/2023	326,699	8.8	275.1	63.9
2/2023	169,396	3.5	119.6	59.2
3/2023	823,821	21.6	535.4	80.8
4/2023	419,313	4.5	295.0	30.4
5/2023	1,513	0.0	23.7	-- (Exclude)
6/2023	274,158	7.5	191.8	77.7
7/2023	1,000,426	20.3	610.5	66.6
8/2023	323,483	9.2	202.8	90.4
9/2023	215,369	5.9	146.5	80.8
10/2023	121,912	3.3	101.0	65.9
11/2023	69,435	2.0	60.7	**66.5**
12/2023	672,079	18.3	389.3	93.8
1/2024	838,800	13.7	515.9	53.2
2/2024	33,211	0.6	30.1	40.1
3/2024	0	0.0	0.0	--
4/2024	192,605	5.3	166.8	64.1
5/2024	276,485	9.3	210.7	88.4
24-month Total		189.4		
Annual Avg		**94.7** tpy		**66.5** Baseline Period Avg.

22.3 Unit 2 Boiler: SO2 Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of SO_2.

> Because the Unit 2 Boiler has a combined SO_2 CEMS where both Unit 1 and 2 use a DFGD SO_2 control device and share the same coal source/fuel input types, the baseline actual emissions can be derived directly from CAMPD without any necessary adjustments. The monthly and overall 24-month annual average baseline actual SO_2 emissions are shown in the table below.

> An annual average emission factor for SO_2 emissions from Unit 2 is derived based on SO_2 CEMS data and total monthly heat input to support the projected actual emission calculations for coal usage

Month	SO_2 CEMS Emissions (tons)	Operating Time (hrs)	SO_2 Emissions (lb/hr)	Coal Heat Input (MMBtu)	Fuel Oil Heat Input (MMBtu)	Total Heat Input (MMBtu)
6/2022	7.8	534.47	29.2	818,470	1,951	820,421
7/2022	11.2	606.23	37.0	896,477	3,199	899,676
8/2022	9.8	394.83	49.5	578,909	2,606	581,515
9/2022	3.7	214.87	34.7	323,198	301	323,500
10/2022	0.0	0	--	0	0	0
11/2022	0.0	0	--	0	0	0
12/2022	0.0	11.55	-- (Exclude)	598	0	598
1/2023	10.3	275.07	75.1	322,843	3,857	326,699
2/2023	2.2	119.56	36.0	168,296	1,100	169,396
3/2023	13.9	535.42	52.0	821,783	2,039	823,821
4/2023	8.6	294.98	58.4	417,921	1,392	419,313
5/2023	0.0	23.69	-- (Exclude)	960	553	1,513
6/2023	4.5	191.78	46.9	272,813	1,346	274,158
7/2023	20.3	610.48	66.5	998,728	1,698	1,000,426
8/2023	8.2	202.75	80.5	321,978	1,506	323,483
9/2023	3.3	146.54	45.3	213,949	1,420	215,369
10/2023	3.5	101	70.2	120,688	1,224	121,912
11/2023	2.8	60.67	92.9	67,600	1,835	69,435
12/2023	10.3	389.29	52.9	670,240	1,839	672,079
1/2024	22.6	515.9	87.5	837,038	1,761	838,800
2/2024	0.3	30.09	21.3	32,781	430	33,211
3/2024	0.0	0	--	0	0	0
4/2024	2.5	166.82	29.7	189,492	3,113	192,605
5/2024	3.6	210.72	34.1	273,339	3,146	276,485
24-month Total	149.4					8,384,413.8
Annual Avg	**74.7**		**52.6**	Baseline Period Avg.		**4,192,206.9**
SO_2 Avg EF	0.036	lb/MMBtu				

22.4 Unit 2 Boiler: H2SO4 Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of H_2SO_4.

H_2SO_4 EF	0.00541 lb/ton
H_2SO_4 EF	0.00021 lb/MMBtu

> EKPC combusts ultra low sulfur diesel oil in the Unit 2 Boiler. With a typical sulfur content of 0.0015% for ULSD, the incremental H2SO4 emissions from fuel oil combustion are negligible and thus are not counted for purposes of defining the baseline emissions.

> The monthly calculated H_2SO_4 emissions from the stack test emission factors during the baseline period are tabulated below.

Month	Coal Heat Input (MMBtu)	H_2SO_4 Emissions (tons)
6/2022	818,470	0.087
7/2022	896,477	0.096
8/2022	578,909	0.062
9/2022	323,198	0.035
10/2022	0	0.000
11/2022	0	0.000
12/2022	598	0.000
1/2023	322,843	0.035
2/2023	168,296	0.018
3/2023	821,783	0.088
4/2023	417,921	0.045
5/2023	960	0.000
6/2023	272,813	0.029
7/2023	998,728	0.107
8/2023	321,978	0.034
9/2023	213,949	0.023
10/2023	120,688	0.013
11/2023	67,600	0.007
12/2023	670,240	0.072
1/2024	837,038	0.089
2/2024	32,781	0.004
3/2024	0	0.000
4/2024	189,492	0.020
5/2024	273,339	0.029
24-month Total		0.89
Annual Avg		**0.45**

<u>Sample Calculations</u>: (for 5/2024)

H2SO4 Emissions = 273,339 MMBtu/mo * 0.00021 lb/MMBtu / 2000 lb/ton = 0.029 ton/mo H2SO4

H2SO4 Annual Average Baseline Emissions = 0.9 tons/24-months / 2 years/24-month = 0.45 tpy H2SO4

22.5 Unit 2 Boiler: CO Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of CO.

22.5.1 CO Emission Factors

> CO emissions from the Unit 2 Boiler can be attributed to both coal combustion and fuel oil combustion. Total emissions are based on the sum of emissions attributable to each fuel.

CO Coal Combustion EF:	0.5 lb/ton	AP-42 1.1 (9/98), Table 1.1-3, for any type of pulverized coal dry bottom furnace
CO Coal Combustion EF:	0.0192 lb/MMBtu	
CO Fuel Oil Combustion EF:	5 lb/Mgal	AP-42 1.3, Table 1.3-1, for boilers > 100 MMBtu/yr

> The monthly coal and fuel oil usage rates during the selected baseline period for Unit 2 along with the calculated CO baseline emissions using the factors cited are shown in the following table.

Month	Coal Heat Input (MMBtu)	CO Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	CO Emissions from Fuel Oil (tons)	Total CO Monthly Emissions (tons)	Operating Time (hrs)	CO Emissions (lb/hr)	
6/2022	818,470	7.87	14.32	0.036	7.91	534.47	29.6	
7/2022	896,477	8.62	23.49	0.059	8.68	606.23	28.6	
8/2022	578,909	5.57	19.13	0.048	5.61	394.83	28.4	
9/2022	323,198	3.11	2.21	0.006	3.11	214.87	29.0	
10/2022	0	0.00	0.00	0.000	0.00	0	--	
11/2022	0	0.00	0.00	0.000	0.00	0	--	
12/2022	598	0.01	0.00	0.000	0.01	11.55	-- (Exclude)	
1/2023	322,843	3.10	28.32	0.071	3.18	275.07	23.1	
2/2023	168,296	1.62	8.07	0.020	1.64	119.56	27.4	
3/2023	821,783	7.90	14.97	0.037	7.94	535.42	29.7	
4/2023	417,921	4.02	10.22	0.026	4.04	294.98	27.4	
5/2023	960	0.01	4.06	0.010	0.02	23.69	-- (Exclude)	
6/2023	272,813	2.62	9.88	0.025	2.65	191.78	27.6	
7/2023	998,728	9.60	12.47	0.031	9.63	610.48	31.6	
8/2023	321,978	3.10	11.05	0.028	3.12	202.75	30.8	
9/2023	213,949	2.06	10.43	0.026	2.08	146.54	28.4	
10/2023	120,688	1.16	8.98	0.022	1.18	101	23.4	
11/2023	67,600	0.65	13.48	0.034	0.68	60.67	22.5	
12/2023	670,240	6.44	13.51	0.034	6.48	389.29	33.3	
1/2024	837,038	8.05	12.93	0.032	8.08	515.9	31.3	
2/2024	32,781	0.32	3.16	0.008	0.32	30.09	21.5	
3/2024	0	0.00	0.00	0.000	0.00	0	--	
4/2024	189,492	1.82	22.86	0.057	1.88	166.82	22.5	
5/2024	273,339	2.63	23.10	0.058	2.69	210.72	25.5	
24-month Total	8,348,100	80.3	266.6	0.667	80.9			
Annual Avg	4,174,050	40.1	133.3	0.333	**40.5**		**27.5**	Baseline Period Avg.

Sample Calculations: (for 5/2024 for Coal and 12/2023 for Fuel Oil)
CO Emissions from Coal = 273,339 MMBtu/mo * 0.0192 lb/MMBtu / 2000 lb/ton = 2.63 tons CO/mo
CO Emissions from Fuel Oil = 13.505 Mgal/mo * 5 lb/Mgal / 2000 lb/ton = 0.034 tons CO/mo
Annual Average Baseline Emissions = 80.9 tons/24-months / 2 years/24-month = 40.5 tpy CO

22.6 Unit 2 Boiler: VOC Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of VOC.

22.6.1 VOC Emission Factors

> VOC emissions from the Unit 2 Boiler can be attributed to both coal combustion and fuel oil combustion. Total emissions are based on the sum of emissions attributable to each fuel.

VOC Coal Combustion EF:	0.06	lb/ton	AP-42 1.1 (9/98), Table 1.1-19, TNMOC for pulverized coal dry bottom furnaces
VOC Coal Combustion EF:	0.0023	lb/MMBtu	
VOC Fuel Oil Combustion EF:	0.2	lb/Mgal	AP-42 1.3, Table 1.3-3, NMTOC factor for distillate oil fired in industrial boilers

> The monthly coal and fuel oil usage rates during the selected baseline period for Unit 2 along with the calculated VOC baseline emissions using the factors cited are shown in the following table.

Month	Coal Heat Input (MMBtu)	VOC Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	VOC Emissions from Fuel Oil (tons)	Total VOC Monthly Emissions (tons)
6/2022	818,470	0.94	14.32	0.0014	0.95
7/2022	896,477	1.03	23.49	0.0023	1.04
8/2022	578,909	0.67	19.13	0.0019	0.67
9/2022	323,198	0.37	2.21	0.0002	0.37
10/2022	0	0.00	0.00	0.0000	0.00
11/2022	0	0.00	0.00	0.0000	0.00
12/2022	598	0.00	0.00	0.0000	0.00
1/2023	322,843	0.37	28.32	0.0028	0.38
2/2023	168,296	0.19	8.07	0.0008	0.19
3/2023	821,783	0.95	14.97	0.0015	0.95
4/2023	417,921	0.48	10.22	0.0010	0.48
5/2023	960	0.00	4.06	0.0004	0.00
6/2023	272,813	0.31	9.88	0.0010	0.32
7/2023	998,728	1.15	12.47	0.0012	1.15
8/2023	321,978	0.37	11.05	0.0011	0.37
9/2023	213,949	0.25	10.43	0.0010	0.25
10/2023	120,688	0.14	8.98	0.0009	0.14
11/2023	67,600	0.08	13.48	0.0013	0.08
12/2023	670,240	0.77	13.51	0.0014	0.77
1/2024	837,038	0.97	12.93	0.0013	0.97
2/2024	32,781	0.04	3.16	0.0003	0.04
3/2024	0	0.00	0.00	0.0000	0.00
4/2024	189,492	0.22	22.86	0.0023	0.22
5/2024	273,339	0.32	23.10	0.0023	0.32
24-month Total	8,348,100	9.6	266.6	0.0267	9.7
Annual Avg	4,174,050	4.8	133.3	0.0133	**4.8**

Sample Calculations: (for 5/2024 for Coal and 12/2023 for Fuel Oil)
VOC Emissions from Coal = 273,339 tons coal/mo * 0.0023 lb/MMBtu / 2000 lb/ton = 0.32 tons VOC/mo
VOC Emissions from Fuel Oil = 13.505 Mgal/mo * 0.2 lb/Mgal / 2000 lb/ton = 0.0014 tons VOC/mo
Annual Average Baseline Emissions = 9.7 tons/24-months / 2 years/24-month = 4.8 tpy VOC

22.7 Unit 2 Boiler: PM/PM10/PM2.5 Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of PM, PM_{10}, and $PM_{2.5}$.

22.7.1 Coal Combustion PM Emission Factors

> EKPC conducts annual emission tests for filterable PM from the Unit 2 Boiler as required by the Title V permit. The emission factor from each year's test is used to calculate actual PM filterable emissions. To accurately estimate the baseline actual emissions, the PM emission factor used is updated in the months when new testing was completed. Thus, there are three different emission factors used within the 24-month baseline period as listed below.

> Note that for annually KyEIS emission inventories, the emission factors from the annual tests (lb/MMBtu) are converted to equivalent lb/ton emission factors based on that year's average coal heating value since the SCC code used has units of tons of coal burned. However, for these baseline actual emission calculations the emission are based directly on the test-derived emission factor (lb/MMBtu) and the actual monthly heat input in Unit 2 from coal to more accurately tally the monthly emission rates used in the 24-month baseline period.

Coal Combustion Emission Factors

PM Filterable EF for 8/2019 to 6/2020:	0.004	lb/MMBtu	Annual PM emission test conducted 8/20/2019
PM Filterable EF for 7/2020 to 7/2021:	0.001	lb/MMBtu	Annual PM emission test conducted 7/17/2020
PM Filterable EF for 8/2021 to 6/2022:	0.001	lb/MMBtu	Annual PM emission test conducted 7/30/2021
PM Filterable EF for 7/2022 to 4/2023:	0.003	lb/MMBtu	Annual PM emission test conducted 6/6/2022
PM Filterable EF for 5/2023 to 6/2024:	0.006	lb/MMBtu	Annual PM emission test conducted 4/28/2023

> As shown in AP-42 Table 1.1-6, for a baghouse controlled coal boiler, 92% of cumulative PM filterable mass can be expected to be PM_{10} and 53% of the cumulative PM filterable mass can be expected to be $PM_{2.5}$.

> Condensable PM emissions from coal combustion are estimated based on the emission factor in AP-42 Section 1.1, Table 1.1-5, for "pulverized coal boilers with PM control combined with FGD control" of 0.02 lb/MMBtu.

PM_{10}/PM Filterable Size Ratio:	0.92		AP-42 1.1 (9/98), Table 1.1-6, Cumulative Mass % for baghouse controlled boiler
$PM_{2.5}$/PM Filterable Size Ratio:	0.53		AP-42 1.1 (9/98), Table 1.1-6, Cumulative Mass % for baghouse controlled boiler
PM Condensable EF for Coal:	0.020	lb/MMBtu	AP-42 1.1 (9/98), Table 1.1-5, Coal boiler with PM controls combined with FGD

22.7.2 Fuel Oil Combustion PM Emission Factors

> Filterable PM emissions attributable to fuel oil combustion are estimated based on the emission factor in AP-42 Section 1.3, Table 1.3-1 for No. 2 oil fired in "Boilers > 100 MMBtu/hr" of 2 lb/Mgal. Filterable PM_{10} and $PM_{2.5}$ emissions attributable to fuel oil combustion are estimated based on the emission factor in AP-42 Section 1.3, Table 1.3-6 for uncontrolled industrial boiler firing distillate oil.

> Condensable PM emissions from fuel oil combustion are estimated based on the emission factor in AP-42 Section 1.3, Table 1.3-2 for No. 2 oil fired boilers of 1.3 lb/Mgal.

> Although condensable PM emissions are not tracked in the annual KyEIS inventory for the Unit 2 Boiler, they are included here for purposes of defining baseline actual emissions since PSD applicability is based on total PM (filterable + condensable).

Uncontrolled PM Filterable EF for Oil:	2.00	lb/Mgal	AP-42 1.3 (5/10), Table 1.3-1, "Boilers > 100 MMBtu/hr", No. 2 oil fired
Uncontrolled PM_{10} Filterable EF for Oil:	1.00	lb/Mgal	AP-42 Chapter 1.3 for Fuel Oil Combustion, Table 1.3-6 (5/10).
Uncontrolled $PM_{2.5}$ Filterable EF for Oil:	0.25	lb/Mgal	AP-42 Chapter 1.3 for Fuel Oil Combustion, Table 1.3-6 (5/10).
PM Control Efficiency for Unit 2	99.24	%	Control efficiency based on baghouse control for Unit 2 per Historical KyEIS.
Controlled PM Filterable EF for Oil:	0.015	lb/Mgal	
Controlled PM_{10} Filterable EF for Oil:	0.008	lb/Mgal	
Controlled $PM_{2.5}$ Filterable EF for Oil:	0.002	lb/Mgal	
PM Condensable EF for Oil:	1.30	lb/Mgal	AP-42 1.3 (5/10), Table 1.3-2, No. 2 oil fired CPM-TOT

22.7.3 Unit 2 Baseline Actual PM/PM10/PM2.5 Emissions from Coal

> The monthly heat input from coal during the selected baseline period along with the calculated filterable, condensable, and total PM, PM_{10}, and $PM_{2.5}$ emissions attributable to coal combustion are shown in the following table.

Month	Coal Heat Input (MMBtu)	PM Filterable Emissions from Coal (tons)	PM_{10} Filterable Emissions from Coal (tons)	$PM_{2.5}$ Filterable Emissions from Coal (tons)	Condens. PM Emissions from Coal (tons)	Total PM Emissions from Coal (tons)	Total PM_{10} Emissions from Coal (tons)	Total $PM_{2.5}$ Emissions from Coal (tons)
6/2022	818,470	0.41	0.38	0.22	8.18	8.59	8.56	8.40
7/2022	896,477	1.34	1.24	0.71	8.96	10.31	10.20	9.68
8/2022	578,909	0.87	0.80	0.46	5.79	6.66	6.59	6.25
9/2022	323,198	0.48	0.45	0.26	3.23	3.72	3.68	3.49
10/2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2022	598	0.00	0.00	0.00	0.01	0.01	0.01	0.01
1/2023	322,843	0.48	0.45	0.26	3.23	3.71	3.67	3.49
2/2023	168,296	0.25	0.23	0.13	1.68	1.94	1.92	1.82
3/2023	821,783	1.23	1.13	0.65	8.22	9.45	9.35	8.87
4/2023	417,921	0.63	0.58	0.33	4.18	4.81	4.76	4.51
5/2023	960	0.00	0.00	0.00	0.01	0.01	0.01	0.01
6/2023	272,813	0.82	0.75	0.43	2.73	3.55	3.48	3.16
7/2023	998,728	3.00	2.76	1.59	9.99	12.98	12.74	11.58
8/2023	321,978	0.97	0.89	0.51	3.22	4.19	4.11	3.73
9/2023	213,949	0.64	0.59	0.34	2.14	2.78	2.73	2.48
10/2023	120,688	0.36	0.33	0.19	1.21	1.57	1.54	1.40
11/2023	67,600	0.20	0.19	0.11	0.68	0.88	0.86	0.78
12/2023	670,240	2.01	1.85	1.07	6.70	8.71	8.55	7.77
1/2024	837,038	2.51	2.31	1.33	8.37	10.88	10.68	9.70
2/2024	32,781	0.10	0.09	0.05	0.33	0.43	0.42	0.38
3/2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2024	189,492	0.57	0.52	0.30	1.89	2.46	2.42	2.20
5/2024	273,339	0.82	0.75	0.43	2.73	3.55	3.49	3.17
24-month Total	8,348,100	17.70	16.29	9.38	83.48	101.18	99.77	92.86
Annual Avg	4,174,050	8.85	8.14	4.69	41.74	50.59	49.88	46.43

<u>Sample Calculations</u>: (for 5/2024)

PM-Filterable Emissions = 273,339 MMBtu/mo * 0.0060 lb/MMBtu / 2000 lb/ton = 0.82 tons/mo PM-Filterable

PM10-Filterable Emissions = 0.82 tons PM-Filt/mo * 0.92 = 0.75 tons/mo PM10-Filterable

PM2.5-Filterable Emissions = 0.82 tons PM-Filt/mo * 0.53 = 0.43 tons/mo PM2.5-Filterable

Condensable PM Emissions = 273,339 MMBtu/mo * 0.02 lb/MMBtu / 2000 lb/ton = 2.73 tons/mo PM Condensable

Total PM Emissions = 0.82 tons PM-Filt/mo + 2.73 tons PM-Cond/mo = 3.55 tons/mo PM

22.7.4 Unit 2 Baseline Actual PM/PM10/PM2.5 Emissions from Fuel Oil

> The monthly fuel oil usage during the selected baseline period along with the calculated filterable, condensable, and total PM, PM_{10}, and $PM_{2.5}$ emissions attributable to fuel oil combustion are shown in the following table.

Month	Fuel Oil Usage (Mgal)	PM Filterable Emissions from Oil (tons)	PM_{10} Filterable Emissions from Oil (tons)	$PM_{2.5}$ Filterable Emissions from Oil (tons)	Condens. PM Emissions from Oil (tons)	Total PM Emissions from Oil (tons)	Total PM_{10} Emissions from Oil (tons)	Total $PM_{2.5}$ Emissions from Oil (tons)
6/2022	14.32	1.09E-04	5.44E-05	1.36E-05	0.0093	0.0094	0.0094	0.0093
7/2022	23.49	1.79E-04	8.93E-05	2.23E-05	0.0153	0.0154	0.0154	0.0153
8/2022	19.13	1.45E-04	7.27E-05	1.82E-05	0.0124	0.0126	0.0125	0.0125
9/2022	2.21	1.68E-05	8.40E-06	2.10E-06	0.0014	0.0015	0.0014	0.0014
10/2022	0.00	0	0	0	0	0	0	0
11/2022	0.00	0	0	0	0	0	0	0
12/2022	0.00	0	0	0	0	0	0	0
1/2023	28.32	2.15E-04	1.08E-04	2.69E-05	0.0184	0.0186	0.0185	0.0184
2/2023	8.07	6.14E-05	3.07E-05	7.67E-06	0.0052	0.0053	0.0053	0.0053
3/2023	14.97	1.14E-04	5.69E-05	1.42E-05	0.0097	0.0098	0.0098	0.0097
4/2023	10.22	7.77E-05	3.88E-05	9.71E-06	0.0066	0.0067	0.0067	0.0067
5/2023	4.06	3.08E-05	1.54E-05	3.85E-06	0.0026	0.0027	0.0027	0.0026
6/2023	9.88	7.51E-05	3.75E-05	9.39E-06	0.0064	0.0065	0.0065	0.0064
7/2023	12.47	9.47E-05	4.74E-05	1.18E-05	0.0081	0.0082	0.0082	0.0081
8/2023	11.05	8.40E-05	4.20E-05	1.05E-05	0.0072	0.0073	0.0072	0.0072
9/2023	10.43	7.92E-05	3.96E-05	9.90E-06	0.0068	0.0069	0.0068	0.0068
10/2023	8.98	6.83E-05	3.41E-05	8.53E-06	0.0058	0.0059	0.0059	0.0058
11/2023	13.48	1.02E-04	5.12E-05	1.28E-05	0.0088	0.0089	0.0088	0.0088
12/2023	13.51	1.03E-04	5.13E-05	1.28E-05	0.0088	0.0089	0.0088	0.0088
1/2024	12.93	9.83E-05	4.91E-05	1.23E-05	0.0084	0.0085	0.0085	0.0084
2/2024	3.16	2.40E-05	1.20E-05	3.00E-06	0.0021	0.0021	0.0021	0.0021
3/2024	0.00	0.00E+00	0.00E+00	0.00E+00	0.0000	0.0000	0.0000	0.0000
4/2024	22.86	1.74E-04	8.69E-05	2.17E-05	0.0149	0.0150	0.0149	0.0149
5/2024	23.10	1.76E-04	8.78E-05	2.19E-05	0.0150	0.0152	0.0151	0.0150
24-month Total	267	2.03E-03	1.01E-03	2.53E-04	0.17	0.18	0.17	0.17
Annual Avg	133	1.01E-03	5.07E-04	1.27E-04	0.09	0.09	0.09	0.09

Sample Calculations: (for 6/2022)
PM-Filterable Emissions = 14.3 Mgal/mo * 0.015 lb/Mgal / 2000 lb/ton = 1.09E-04 tons/mo PM-Filterable
Condensable PM Emissions = 14.3 Mgal/mo * 1.3 lb/gal / 2000 lb/ton = 9.31E-03 tons/mo PM Condensable
Total PM Emissions = 0.0001 tons PM-Filt/mo + 0.0093 tons PM-Cond/mo = 0.0094 tons/mo PM

22.7.5 Unit 2 Baseline Actual PM/PM10/PM2.5 Emissions Total from Coal and Fuel Oil Combined

> Based on the separately tallied PM emissions from coal and fuel oil for each month in the selected baseline period, the total combined PM emissions are shown in the following table.

Month	Filt. PM Emissions (Coal+Oil) (tons)	Total PM_{10} Emissions (Coal+Oil) (tons)	Total $PM_{2.5}$ Emissions (Coal+Oil) (tons)	Operating Time (hrs)	PM Emissions (lb/hr)	PM_{10} Emissions (lb/hr)	$PM_{2.5}$ Emissions (lb/hr)
6/2022	0.41	8.57	8.41	534.47	1.5	32.1	31.5
7/2022	1.34	10.22	9.69	606.23	4.4	33.7	32.0
8/2022	0.87	6.60	6.26	394.83	4.4	33.4	31.7
9/2022	0.48	3.68	3.49	214.87	4.5	34.2	32.5
10/2022	0.00	0.00	0.00	0	--	--	--
11/2022	0.00	0.00	0.00	0	--	--	--
12/2022	0.00	0.01	0.01	11.55	-- (Exclude)	-- (Exclude)	-- (Exclude)
1/2023	0.48	3.69	3.50	275.07	3.5	26.8	25.5
2/2023	0.25	1.92	1.82	119.56	4.2	32.1	30.5
3/2023	1.23	9.36	8.88	535.42	4.6	35.0	33.2
4/2023	0.63	4.76	4.52	294.98	4.3	32.3	30.6
5/2023	0.00	0.01	0.01	23.69	-- (Exclude)	-- (Exclude)	-- (Exclude)
6/2023	0.82	3.49	3.17	191.78	8.5	36.4	33.0
7/2023	3.00	12.75	11.58	610.48	9.8	41.8	37.9
8/2023	0.97	4.12	3.74	202.75	9.5	40.6	36.9
9/2023	0.64	2.74	2.49	146.54	8.8	37.4	33.9
10/2023	0.36	1.55	1.40	101	7.2	30.6	27.8
11/2023	0.20	0.87	0.79	60.67	6.7	28.7	26.1
12/2023	2.01	8.56	7.78	389.29	10.3	44.0	40.0
1/2024	2.51	10.69	9.71	515.9	9.7	41.4	37.6
2/2024	0.10	0.42	0.38	30.09	6.5	27.9	25.4
3/2024	0.00	0.00	0.00	0	--	--	--
4/2024	0.57	2.43	2.21	166.82	6.8	29.2	26.5
5/2024	0.82	3.50	3.18	210.72	7.8	33.2	30.2
24-month Total	17.71	99.94	93.04				
Annual Avg	**8.9**	**50.0**	**46.5**		**6.5**	**34.3**	**31.7**

<u>Sample Calculations</u>: (for 5/2024)

Combined PM10 Total Emissions = 3.49 tons/mo from Coal + 0.0151 tons/mo from Oil = 3.50 tons/mo Total PM10

Annual Average Baseline PM10 Emissions = 99.94 tons/24-months / 2 years/24-month = 50.0 tpy Total PM10

22.8 Lead Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of lead.

22.8.1 Lead Emission Factors

> For annual emission inventory purposes, uncontrolled lead emissions from coal combustion for the Unit 2 boiler have historically calculated based on the methodology specified in AP-42 Section 1.1, Table 1.1-17.

> Uncontrolled lead emissions from fuel oil combustion for the Unit 2 boiler are estimated based on the methodology specified in AP-42 Section 1.3, Table 1.3-10 for trace elements from distillate fuel oil combustion sources.

Lead EF for Coal (Uncontrolled):	5.07E-04	lb/MMBtu	AP-42 1.1 (9/98), Table 1.1-17, for any type of pulverized coal dry bottom furnace
Lead EF for Fuel Oil (Uncontrolled):	1.26E-03	lb/Mgal	AP-42 Chapter 1.3 for Fuel Oil Combustion, Table 1.3-10 (5/10), converted to lb/Mgal using 140 MMBtu/Mgal from AP-42
KyEIS Control Efficiency	99.74%		Per 2022 DAQ-accepted Web Survey
Lead EF for Coal (Controlled):	1.32E-06	lb/MMBtu	0.000507 lb/MMBtu * (1-0.9974) = 1.32E-06 lb/MMBtu
Lead EF for Fuel Oil (Controlled):	3.28E-06	lb/Mgal	0.00126 lb/Mgal * (1-0.9974) = 3.28E-06 lb/Mgal

> The monthly coal usage during the selected baseline period for the Unit 2 boiler and calculated baseline emissions for lead are shown in the following table.

Month	Coal Heat Input (MMBtu)	Lead Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	Lead Emissions from FO (tons)	Total Lead Monthly Emissions (tons)
6/2022	818,470	5.39E-04	14.32	2.35E-08	5.39E-04
7/2022	896,477	5.91E-04	23.49	3.85E-08	5.91E-04
8/2022	578,909	3.82E-04	19.13	3.13E-08	3.82E-04
9/2022	323,198	2.13E-04	2.21	3.62E-09	2.13E-04
10/2022	0.00	0.00	0.00	0.00	0.00
11/2022	0.00	0.00	0.00	0.00	0.00
12/2022	598	3.94E-07	0.00	0.00E+00	3.94E-07
1/2023	322,843	2.13E-04	28.32	4.64E-08	2.13E-04
2/2023	168,296	1.11E-04	8.07	1.32E-08	1.11E-04
3/2023	821,783	5.42E-04	14.97	2.45E-08	5.42E-04
4/2023	417,921	2.75E-04	10.22	1.67E-08	2.75E-04
5/2023	960	6.33E-07	4.06	6.65E-09	6.39E-07
6/2023	272,813	1.80E-04	9.88	1.62E-08	1.80E-04
7/2023	998,728	6.58E-04	12.47	2.04E-08	6.58E-04
8/2023	321,978	2.12E-04	11.05	1.81E-08	2.12E-04
9/2023	213,949	1.41E-04	10.43	1.71E-08	1.41E-04
10/2023	120,688	7.95E-05	8.98	1.47E-08	7.96E-05
11/2023	67,600	4.46E-05	13.48	2.21E-08	4.46E-05
12/2023	670,240	4.42E-04	13.51	2.21E-08	4.42E-04
1/2024	837,038	5.52E-04	12.93	2.12E-08	5.52E-04
2/2024	32,781	2.16E-05	3.16	5.17E-09	2.16E-05
3/2024	0.00	0.00	0.00	0.00	0.00
4/2024	189,492	1.25E-04	22.86	3.74E-08	1.25E-04
5/2024	273,339	1.80E-04	23.10	3.78E-08	1.80E-04
24-month Total	8,348,100	5.50E-03	267	4.37E-07	5.50E-03
Annual Avg	4,174,050	2.75E-03	133	2.18E-07	**2.75E-03**

Sample Calculations: (for 6/2022)
Lead Emissions from Coal= 818,470 MMBtu/mo * 1.32E-06 lb/MMBtu / 2000 lb/ton = 5.39E-04 ton/mo lead
Lead Emissions from Fuel Oil= 14.32 Mgal/mo * 3.28E-06 lb/Mgal / 2000 lb/ton = 2.35E-08 ton/mo lead
Total Lead Emissions= 5.39E-04 ton/mo lead from coal + 2.35E-08 ton/mo lead from fuel oil = 5.39E-04 ton/mo total
Annual Average Baseline Emissions = 5.50E-03 tons/24-months / 2 years/24-month = 2.75E-03 tpy lead

22.9 Unit 2 Boiler: CO2e Baseline Actual Emissions

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of CO_2e.

22.9.1 GHG Emission Factors

> Because the Unit 2 Boiler has a CO_2 CEMS, the baseline actual emissions for CO_2 are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual CO_2 emissions are shown in the table below.

> Emission factors for methane and nitrous oxide from both coal and fuel oil combustion are based on Subpart C of EPA's Greenhouse Gas Reporting Program (GHGRP, 40 CFR 98 Subpart C Table C-2).

> The global warming multiplying factors for CH_4 and N_2O are those specified in 40 CFR 98, Subpart A.

Coal CH_4 Emission Factor:	1.10E-02	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Fuel Oil CH_4 Emission Factor:	3.00E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Coal N_2O Emission Factor:	1.60E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Fuel Oil N_2O Emission Factor:	6.00E-04	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Coal Higher Heating Value:	24.93	MMBtu/ton	40 CFR 98 Subpart C, Table C-1 for Bituminous Coal
Fuel Oil Higher Heating Value:	0.138	MMBtu/gal	40 CFR 98 Subpart C, Table C-1 for Distillate Fuel Oil No. 2
Global warming multiplying factors to calculate CO_2e emissions:			
GWP for CO_2:	1		40 CFR 98 Subpart A, Table A-1 (89 FR 31894, Apr. 25, 2024)
GWP for CH_4:	28		40 CFR 98 Subpart A, Table A-1 (89 FR 31894, Apr. 25, 2024)
GWP for N_2O:	265		40 CFR 98 Subpart A, Table A-1 (89 FR 31894, Apr. 25, 2024)

> The monthly coal and oil heat input rates during the selected baseline period for Unit 2 are shown in the following table. The baseline actual CO_2e emissions are calculated based on the directly measured CO_2 emissions and the calculated CH_4 and N_2O emissions as shown.

Month	Measured CO_2 CEMS Emissions (tons)	Coal Heat Input (MMBtu)	CH_4 Emissions from Coal (tons)	N_2O Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	CH_4 Emissions from Oil (tons)	N_2O Emissions from Oil (tons)	CO_2e Emissions (tons)
6/2022	83,975	818,470	9.92	1.44	14.32	6.54E-03	1.31E-03	84,636
7/2022	91,978	896,477	10.87	1.58	23.49	1.07E-02	2.14E-03	92,702
8/2022	59,396	578,909	7.02	1.02	19.13	8.73E-03	1.75E-03	59,863
9/2022	33,160	323,198	3.92	0.57	2.21	1.01E-03	2.02E-04	33,421
10/2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2022	61	598	0.01	0.00	0.00	0.00	0.00	62
1/2023	33,124	322,843	3.91	0.57	28.32	1.29E-02	2.58E-03	33,385
2/2023	17,267	168,296	2.04	0.30	8.07	3.68E-03	7.37E-04	17,403
3/2023	84,316	821,783	9.96	1.45	14.97	6.83E-03	1.37E-03	84,979
4/2023	42,879	417,921	5.07	0.74	10.22	4.66E-03	9.33E-04	43,216
5/2023	98	960	0.01	0.00	4.06	1.85E-03	3.70E-04	99
6/2023	27,990	272,813	3.31	0.48	9.88	4.51E-03	9.02E-04	28,211
7/2023	102,469	998,728	12.11	1.76	12.47	5.69E-03	1.14E-03	103,275
8/2023	33,035	321,978	3.90	0.57	11.05	5.04E-03	1.01E-03	33,295
9/2023	21,951	213,949	2.59	0.38	10.43	4.76E-03	9.52E-04	22,124
10/2023	12,383	120,688	1.46	0.21	8.98	4.10E-03	8.20E-04	12,481
11/2023	6,936	67,600	0.82	0.12	13.48	6.15E-03	1.23E-03	6,991
12/2023	68,767	670,240	8.13	1.18	13.51	6.16E-03	1.23E-03	69,309
1/2024	85,880	837,038	10.15	1.48	12.93	5.90E-03	1.18E-03	86,556
2/2024	3,363	32,781	0.40	0.06	3.16	1.44E-03	2.88E-04	3,390
3/2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2024	19,442	189,492	2.30	0.33	22.86	1.04E-02	2.09E-03	19,596
5/2024	28,045	273,339	3.31	0.48	23.10	1.05E-02	2.11E-03	28,267
24-month Total	856,517	8,348,100	101.2	14.72	267	1.22E-01	2.43E-02	863,262
Annual Avg	428,258	4,174,050	50.6	7.36	133	6.08E-02	1.22E-02	**431,631**

Sample Calculations: (for 6/2022)

CH4 Emissions = 818,470 MMBtu/mo * 1.10E-02 kg/MMBtu * 2.20462 lb/kg / 2000 lb/ton +
14.32 Mgal/mo * 1,000 gal/Mgal * 0.138 MMBtu/gal * 3.00E-03 kg/MMBtu * 2.20462 lb/kg/2,000 lb/ton = 9.93 ton CH4/mo total

N2O Emissions = 818,470 MMBtu/mo x 1.60E-03 kg/MMBtu x 2.20462 lb/kg / 2000 lb/ton +
14.32 Mgal/mo * 1,000 gal/Mgal * 0.138 MMBtu/gal * 6.00E-04 kg/MMBtu * 2.20462 lb/kg/2,000 lb/ton = 1.44 ton N2O/mo total

Annual Average Baseline CO2e Emissions = 428,258 tpy CO2 + (50.7 tpy CH4 x 28) + (7.4 tpy N2O * 265) = 431,631 tpy CO2e

23. Coal Handling Operations for BAE

> With the C2 conversion project, coal projections are greater than baseline actual coal throughput. Therefore, EKPC is projecting an increase in coal handling emissions associated with the project, which will result in PM/PM_{10}/$PM_{2.5}$ increases that are documented in this section.

23.1 PM/PM10/PM2.5 Emission Factors Used for Baseline Actual Emissions Calculations

> EKPC has selected the 24-month period ending May 2024 for defining baseline actual emissions of PM, PM_{10}, and $PM_{2.5}$.

23.1.1 PM Emission Factors from Hopper and Conveyor Transfers

> EKPC has historically calculated actual PM, PM_{10} and $PM_{2.5}$ emissions for the coal handling operations for annual emission inventory purposes using emission factors originally published by the Midwest Research Institute (MRI). Additional particulate speciation has been applied using AP-42, Section 13.2.4.3.

> One set of emission factors is used for transfers to coal receiving hoppers and another set is used for belt conveyor transfers. The uncontrolled emission factors are reduced by 70% due to the presence of dust suppression measures. The same 70% control efficiency that has been historically applied to account for the enclosure of the transfer points is retained for the baseline actual emission calculations.

	PM EF (lb/ton)	PM_{10} EF (lb/ton)	$PM_{2.5}$ EF (lb/ton)	Control Efficiency (%)	Basis
Receiving Hoppers	4.00E-04	1.89E-04	2.86E-05	70%	Historical KyEIS; AP-42 Section 13.2.4.3
Conveyor Transfer Points	3.00E-04	1.42E-04	2.15E-05	70%	Historical KyEIS; AP-42 Section 13.2.4.3

23.1.2 PM Emission Factors from Coal Stockpile Operations

> Fugitive PM emissions can result from wind erosion when gusts of wind cause loose material on the surface of a pile to become airborne. The annual quantity of emissions is assumed to be dependent on the silt content of the material stored, the moisture of the pile (predicted by the number of days per year with measureable precipitation), and the percentage of hours per year that the wind speed exceeds a threshold speed of 12 miles per hour. Emissions factors are calculated using the method from the EPA Document "Control of Open Fugitive Dust Sources".

	PM EF (lb/ton)	PM_{10} EF (lb/ton)	$PM_{2.5}$ EF (lb/ton)	Control Efficiency (%)	Basis
Coal Stockpile	6.14E-03	2.91E-03	4.40E-04	70%	EPA Document "Control of Open Fugitive Dust Sources"

23.1.3 PM Emission Factors from Coal Crusher

> EKPC has historically calculated actual PM, PM_{10} and $PM_{2.5}$ emissions from the coal crusher operations for annual emission inventory purposes using emission factors originally published by the Midwest Research Institute (MRI). Additional particulate speciation has been applied using AP-42, Appendix B, Table B.2.2.

> The coal crushers are controlled by 70% due to the presence of dust suppression measures. The same 70% control efficiency that has been historically applied is retained for the baseline actual emission calculations.

	PM EF (lb/ton)	PM_{10} EF (lb/ton)	$PM_{2.5}$ EF (lb/ton)	Control Efficiency (%)	Basis
Coal Crusher (Routed to Wet Scrubber)	2.00E-04	1.02E-04	3.00E-05	70%	Historical KyEIS; AP-42 Appendix B, Table B.2.2 for Mechanically Generated Aggregate, Unprocessed Ores

23.1.4 PM Emission Factors from Roads

> EKPC has historically calculated actual PM, PM_{10} and $PM_{2.5}$ emissions from paved and unpaved roads using methodologies published in AP-42.

> The road emissions are controlled by 70% due to the presence of dust suppression measures. The same 70% control efficiency that has been historically applied is retained for the baseline actual emission calculations.

	PM EF (lb/VMT)	PM_{10} EF (lb/VMT)	$PM_{2.5}$ EF (lb/VMT)	Control Efficiency (%)	Basis
Unpaved Roads (EU3)	5.197	1.341	0.134	70%	AP-42; Historical KyEIS
Paved Roads (EU10)	0.339	0.068	1.66E-02	70%	AP-42; Historical KyEIS

23.2 Coal Usage and VMT Associated with EKPC Unit 3/7/10 Boiler During Baseline Period

> The monthly coal/run of mine usage rates for the Unit 3, 7, and 10 coal handling and roads associated with the C2 boiler during the selected baseline period are shown in the following table. EU03 road VMT assumes 40 tons of coal per truck, and 0.1 miles per truck trip. EU10 VMT assumes 40 tons of coal per truck, and 0.3 miles per truck trip.

Month	C2 Coal Usage (tons)	EU03 VMT	EU10 VMT
6/2022	32,325	81	242
7/2022	35,406	89	266
8/2022	22,864	57	171
9/2022	12,765	32	96
10/2022	0	0	0
11/2022	0	0	0
12/2022	24	0	0
1/2023	12,751	32	96
2/2023	6,647	17	50
3/2023	32,456	81	243
4/2023	16,506	41	124
5/2023	38	0	0
6/2023	10,775	27	81
7/2023	39,444	99	296
8/2023	12,716	32	95
9/2023	8,450	21	63
10/2023	4,767	12	36
11/2023	2,670	7	20
12/2023	26,471	66	199
1/2024	33,059	83	248
2/2024	1,295	3	10
3/2024	0	0	0
4/2024	7,484	19	56
5/2024	10,795	27	81
24-month Total	329,706	824	2,473
Annual Avg	164,853	412	1,236

23.3 Coal Handling Operations Baseline Actual PM/PM10/PM2.5 Emissions

> The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on the 24-month annual average coal usage in the baseline period and the PM, PM_{10}, and $PM_{2.5}$ emission factors as shown in the tables below.

> A control efficiency of 70% is applied to certain coal handling processes as described in the preceding sections. A control efficiency of 90% is applied to EU03, Process ID 06 (Drop Pit into Bunkers) due to the enclosed nature of this coal handling activity.

23.3.1 Baseline Actual Emissions - PM

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Usage/ Distance in Baseline Period (tpy or VMT)	PM Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	PM Filterable Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	164,853	4.00E-04	70%	0.0099
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	164,853	2.00E-04	70%	0.0049
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	164,853	3.00E-04	70%	0.0074
3	EQPT1,03	04	Reclaim Hopper	164,853	1.50E-03	70%	0.0371
3	EQPT1,03	05	Stockpile	164,853	6.14E-03	70%	0.1519
3	EQPT1,03	06	Drop Pt into Bunkers	164,853	1.50E-03	90%	0.0124
3	EQPT1,03	09	Unpaved Yard Area	412	5.197	70%	0.3213
10	AREA2,010	01	Paved Roads	1,236	0.339	70%	0.0628
Total Baseline Emissions for PM							**0.6077**

Sample Calculations: (for EU 7-1)
PM Emissions = 164,853 tpy of coal * 0.0004 lb/ton * (1-0.7) / 2000 lb/ton = 0.0099 tpy PM

23.3.2 Baseline Actual Emissions - PM10

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Usage/ Distance in Baseline Period (tpy or VMT)	PM_{10} Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	PM_{10} Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	164,853	1.89E-04	70%	0.0047
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	164,853	1.02E-04	70%	0.0025
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	164,853	1.42E-04	70%	0.0035
3	EQPT1,03	04	Reclaim Hopper	164,853	7.09E-04	70%	0.0175
3	EQPT1,03	05	Stockpile	164,853	2.91E-03	70%	0.0718
3	EQPT1,03	06	Drop Pt into Bunkers	164,853	7.09E-04	90%	0.0058
3	EQPT1,03	09	Unpaved Yard Area	412	1.341	70%	0.0829
10	AREA2,010	01	Paved Roads	1,236	0.068	70%	0.0126
Total Baseline Emissions for PM_{10}							**0.2014**

Sample Calculations: (for EU 7-1)
PM10 Emissions = 164,853 tpy of coal * 0.0002 lb/ton * (1-0.7) / 2000 lb/ton = 0.0047 tpy PM10

23.3.3 Baseline Actual Emissions - PM2.5

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Usage/ Distance in Baseline Period (tpy or VMT)	$PM_{2.5}$ Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	$PM_{2.5}$ Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	164,853	2.86E-05	70%	0.0007
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	164,853	3.00E-05	70%	0.0007
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	164,853	2.15E-05	70%	0.0005
3	EQPT1,03	04	Reclaim Hopper	164,853	1.07E-04	70%	0.0027
3	EQPT1,03	05	Stockpile	164,853	4.40E-04	70%	0.0109
3	EQPT1,03	06	Drop Pt into Bunkers	164,853	1.07E-04	90%	0.0009
3	EQPT1,03	09	Unpaved Yard Area	412	0.134	70%	0.0083
10	AREA2,010	01	Paved Roads	1,236	0.017	70%	0.0031
Total Baseline Emissions for $PM_{2.5}$							**0.0278**

Sample Calculations: (for EU 7-1)

PM10 Emissions = 164,853 tpy of coal * 0.0000 lb/ton * (1-0.7) / 2000 lb/ton = 0.0007 tpy PM10

23.4 Coal Handling Projected Actual Emissions

> The baseline actual PM/PM_{10}/$PM_{2.5}$ emissions are calculated based on the 24-month annual average coal usage in the baseline period and the PM, PM_{10}, and $PM_{2.5}$ emission factors as shown in the tables below.

23.4.1 Projected Actual Emissions - PM

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Projected Actual Usage/ Distance (tpy or VMT)	PM Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	PM Filterable Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	165,570	4.00E-04	70%	0.0099
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	165,570	2.00E-04	70%	0.0050
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	165,570	3.00E-04	70%	0.0075
3	EQPT1,03	04	Reclaim Hopper	165,570	1.50E-03	70%	0.0373
3	EQPT1,03	05	Stockpile	165,570	6.14E-03	70%	0.1525
3	EQPT1,03	06	Drop Pt into Bunkers	165,570	1.50E-03	90%	0.0124
3	EQPT1,03	09	Unpaved Yard Area	414	5.197	70%	0.3227
10	AREA2,010	01	Paved Roads	1,242	0.339	70%	0.0631
Total Projected Actual Emissions for PM							**0.6103**

Sample Calculations: (for EU 7-1)

PM Emissions = 165,570 tpy of coal * 0.0004 lb/ton * (1-0.7) / 2000 lb/ton = 0.0099 tpy PM

23.4.2 Projected Actual Emissions - PM10

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Projected Actual Usage/ Distance (tpy or VMT)	PM_{10} Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	PM_{10} Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	165,570	1.89E-04	70%	0.0047
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	165,570	1.02E-04	70%	0.0025
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	165,570	1.42E-04	70%	0.0035
3	EQPT1,03	04	Reclaim Hopper	165,570	7.09E-04	70%	0.0176
3	EQPT1,03	05	Stockpile	165,570	2.91E-03	70%	0.0721
3	EQPT1,03	06	Drop Pt into Bunkers	165,570	7.09E-04	90%	0.0059
3	EQPT1,03	09	Unpaved Yard Area	414	1.341	70%	0.0832
10	AREA2,010	01	Paved Roads	1,242	0.068	70%	0.0126
Total Projected Actual Emissions for PM_{10}							**0.2023**

Sample Calculations: (for EU 7-1)
PM10 Emissions = 165,570 tpy of coal * 0.0002 lb/ton * (1-0.7) / 2000 lb/ton = 0.0047 tpy PM10

23.4.3 Projected Actual Emissions - PM2.5

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Projected Actual Usage/ Distance (tpy or VMT)	$PM_{2.5}$ Emission Factor (lb/ton or lb/VMT)	Control Efficiency (%)	$PM_{2.5}$ Emissions (tpy)
Coal Handling Operations							
3/7	EQPT1,03; EQPT4,07	01	Receiving Hopper	165,570	2.86E-05	70%	0.0007
3/7	EQPT1,03; EQPT4,07	02	Crusher (Primary or Secondary)	165,570	3.00E-05	70%	0.0007
3/7	EQPT1,03; EQPT4,07	03	Convey & Transfer	165,570	2.15E-05	70%	0.0005
3	EQPT1,03	04	Reclaim Hopper	165,570	1.07E-04	70%	0.0027
3	EQPT1,03	05	Stockpile	165,570	4.40E-04	70%	0.0109
3	EQPT1,03	06	Drop Pt into Bunkers	165,570	1.07E-04	90%	0.0009
3	EQPT1,03	09	Unpaved Yard Area	414	0.134	70%	0.0083
10	AREA2,010	01	Paved Roads	1,242	0.017	70%	0.0031
Total Projected Actual Emissions for $PM_{2.5}$							**0.0279**

Sample Calculations: (for EU 7-1)
PM10 Emissions = 165,570 tpy of coal * 0.0000 lb/ton * (1-0.7) / 2000 lb/ton = 0.0007 tpy PM10

23.5 Coal Handling Associated Emissions Increase

> In accordance with 401 KAR 51:017 Section 1(4)(a) and (b), the emissions increase for an existing emission unit is the difference between the projected actual emissions (excluding emissions that could have been accommodated and are unrelated to the project) and the baseline actual emissions.

Pollutant	**PAE** (tpy)	**BAE** (tpy)	**Coal Handling Emissions Increase (PAE - BAE)** (tpy)
PM-FIL	0.610	0.608	2.64E-03
PM_{10}-TOT	0.202	0.201	8.76E-04
$PM_{2.5}$-TOT	0.0279	0.0278	1.21E-04

24. Derivation of Emissions Factors and Calculations for EU 34: 93% Sulfuric Acid Tank

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for 34: 93% Sulfuric Acid Tank are documented in this section.

Emission Unit ID: 34
Emission Unit Name: 93% Sulfuric Acid Tank
Emission Unit Description: 93% Sulfuric Acid Tank
Equipment ID (SI): EQPT0031

24.1 Process Unit(s)

Process ID: 01
EU ID - PID: 34-01
Process Description: Breathing Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: IA-30
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: 02
EU ID - PID: 34-02
Process Description: Working Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: IA-30
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 1/1/2027
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

24.2 93% Sulfuric Acid Tank Operational Data and Specifications for Emission Unit 34

Max Annual Operating Hours	8,760	hr/yr	
Tank Volume	3,000	gal	Design specification
	401.0	ft^3	Unit Conversion: 3000 gal * 7.48 ft3/gal
Tank Height	6.34	ft	Design specification
Tank Diameter	12.69	ft	Design specification
H_2SO_4 Throughput	20,000	gal/yr	Conservative estimate for annual facility-wide consumption
	2.28	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	6.67	turnovers/yr	= 20,000 gal/yr / 3,000 gal
True Vapor Pressure	9.78E-06	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	56.51	°F	Calculated by TankESP
Average Liquid Surface Temperature	57.63	°F	Calculated by TankESP

24.3 Potential Emissions Summary for Emission Unit 34

Storage Tank	Pollutant	Standing Loss Emission Factor (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Sulfuric Acid Tank	H_2SO_4	6.77E-05	4.46E-06	TankESP analysis using methodology presented in AP-42 Section 7.1 and sulfuric acid partial pressure data from Perry's Chemical Engineer's Handbook, 8th Edition	2.03E-04	8.93E-05	3.34E-08	1.46E-07

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

Sample Calculation of Estimated Emissions - Fixed-Roof Tanks

The emissions estimates calculated below are based on EPA's AP-42 Chapter 7.1 (Post 2018) emission factors and equations,

Company:
Location: **EKPC Cooper Station**
Calculations for Tank No.: **EU34**
Emission estimates per EPA's AP-42 Chapter 7.1 (Post 2018), for: **annual 2024**

Meteorological Data:

Avg Atmos Pressure, Pa:	**14.184912**	psia
Avg Ambient Temp, Taa:	**55.5523224**	degrees F
Avg Daily Temp Range, ∆Ta:	**17.9046995**	degrees F
Avg Daily Solar Insolation, I:	**1281.97828**	Btu / ft^2 day

Tank Data:

Tank Type:	**FixedRoof**		shell color:	**white paint**
Average alpha:	**0.25**		shell condition:	**Average**
Tank Diameter:	**12.69**	ft	shell alpha:	**0.25**
Tank Height:	**6.34**	ft	roof color:	**white paint**
Maximum Fill Height:	**5.34**	ft	roof condition:	**Average**
Minimum Liquid Level:	**1**	ft	roof alpha:	**0.25**
Net Working Height:	**4.34**	ft		
Fixed Roof Type:	**self-supporting (dome)**		effective roof height:	**0.87041** ft
Average outage, H_{VO}:	**4.04041288**	ft	Hvo:	**4.04041** ft
Max Vent Setting:	**0.03**	psig		
Min Vent Setting:	**-0.03**	psig		

Service Data:

Service (stored liquid):	**93% Sulfuric Acid Solution**			
Product Factor, K_P:	**1**			Vapor Pressure Constants:
Reid VaporPressure:		psi	(if specified)	A:
ASTM Distillation Slope:			(if specified)	B:
Molecular Weight, M_V:	**18.9882597**	lb/lb-mol		C:
Liquid Bulk Temp, Tb:	**56.5**	degrees F		
Constant Temp Tank?	**NO**		tank must be insulated for temperature to be constant	
Liquid Bulk Temp Basis?	calculated from ambient, per AP-42 equation 1-31			
Liquid Surface Temp, Tla:	**57.6**	degrees F	per AP-42 equation 1-27, 1-28, 1-29	
True Vapor Pressure, P:	**9.78E-06**	psia	per AP-42 equation 1-24, 1-25, 1-26	
Stock Vapor Density, W_V:	**3.34E-08**	lb/ft^3	per AP-42 equation 1-22	

Heating Cycles:

Vapor Space Temp., Tv:	58.74696	degree F	per AP-42 equation 1-32, 1-33, 1-34
Max Liquid Bulk Temp:		degrees F	
Min Liquid Bulk Temp:		degrees F	
Heating cycle frequency:		days	

Operational Data:

Throughput:	**476**	bbl per year
Days this Period:	**366**	days
Turnover Rate:	**4.9**	turnovers per year
Turnover Factor, K_N:	**1.000**	

Calculated Values:

Vapor Space Expansion Factor, $K_E = \{\Delta T_V / (T + 459.67)\} + \{(\Delta P_V - \Delta P_B) / (P_A - P)\}$ AP-42 eqn 1-5

where:

ΔT_V = 19.00507 deg F (deg R); daily temperature range in the vapor space AP-42 eqn 1-6, 1-7, 1-8

Tlx = 62.38 deg F Pvx = 0.000 psia

Tln = 52.88 deg F Pvn = 0.000 psia

ΔP_V = **5.261E-06** psia

ΔP_B = 0.06 psi; vent setting range

K_E = **0.0325095**

Vented Vapor Saturation Factor, $K_S = 1 / (1+ 0.053\ P\ H_{VO})$ AP-42 eqn 1-21

K_S = **0.9999979**

Vent Setting Correction Factor, K_B:

K_B = 1; except when:

$K_N [(P_{BP} + P_A) / (P_I + P_A)] > 1$ AP-42 eqn 1-40

$K_B = [(P_I + P_A)/K_N - P] / [P_{BP} + P_A - P]$ AP-42 eqn 1-41

where:

P_{BP} = 0.03 psig; vent pressure setting

P_I = 0 psig; initial gauge pressure (nominal operating pressure)

K_B = **1**

Control Effi= **0**

Emissions Estimate for: **annual 2024**

Standing Storage Loss:	**2.03E-04**	lb per year	AP-42 eqn 1-4
Working Loss:	**8.93E-05**	lb per year	AP-42 eqn 1-35
Total Emissions (w/o heating cycle loss):	**2.92E-04**	lb per year	AP-42 eqn 1-1
	1.46E-07	tons per year	
Standing Storage Loss(with control):	**2.03E-04**	lb per year	
Working Loss(with control):	**8.93E-05**	lb per year	
Total Emissions(with control):	**2.92E-04**	lb per year	
	1.46E-07	tons per year	

APPENDIX C. AIR PERMIT APPLICATION FORMS

Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

(502) 564-3999

DEP7007AI

Administrative Information

___ Section AI.1: Source Information

___ Section AI.2: Applicant Information

___ Section AI.3: Owner Information

___ Section AI.4: Type of Application

___ Section AI.5: Other Required Information

___ Section AI.6: Signature Block

___ Section AI.7: Notes, Comments, and Explanations

Additional Documentation

None

___ Additional Documentation attached

Source Name: East Kentucky Power Cooperative, Inc.

KY EIS (AFS) #: 21- 161-00009

Permit #: V-18-027

Agency Interest (AI) ID: 3808

Date: 1/24/2025

Section AI.1: Source Information

Physical Location Address:	**Street:**	State Highway 1247 South				
	City:	Burnside	**County**	Pulaski	**Zip Code:**	42519
Mailing Address:	**Street or P.O. Box:**	State Highway 1247 South				
	City:	Burnside	**State:**	Kentucky	**Zip Code:**	42519

Standard Coordinates for Source Physical Location

Longitude: -84.592 (decimal degrees) **Latitude:** 37.000 (decimal degrees)

Primary (NAICS) Category: Electric Power Generation **Primary NAICS #:** 221112

Classification (SIC) Category: Electric Power Generation **Primary SIC #:** 4911

Briefly discuss the type of business conducted at this site: Generation of electrical power from fossil fuel combustion.

Description of Area Surrounding Source:

- ☑ Rural Area
- ☐ Industrial Park
- ☐ Residential Area
- ☐ Urban Area
- ☐ Industrial Area
- ☐ Commercial Area

Is any part of the source located on federal land? ☐ Yes ☑ No

Number of Employees: Approximately 76

Approximate distance to nearest residence or commercial property: < 2000 ft

Property Area: ~860 acres

Is this source portable? ☐ Yes ☑ No

What other environmental permits or registrations does this source currently hold or need to obtain in Kentucky?

NPDES/KPDES:	☑ Currently Hold	☐ Need	☐ N/A
Solid Waste:	☑ Currently Hold	☐ Need	☐ N/A
RCRA:	☑ Currently Hold	☐ Need	☐ N/A
UST:	☐ Currently Hold	☐ Need	☑ N/A

Type of Regulated Waste Activity:

- ☐ Mixed Waste Generator
- ☑ Generator
- ☐ Recycler
- ☐ Other: ______________
- ☐ U.S. Importer of Hazardous Waste
- ☐ Transporter
- ☐ Treatment/Storage/Disposal Facility
- ☐ N/A

Section AI.2: Applicant Information

Applicant Name: East Kentucky Power Cooperative, Inc. (John Sherman Cooper Power Station)

Title: (if individual)

Mailing Address:
Street or P.O. Box: 4775 Lexington Road, P.O. Box 707
City: Winchester **State:** KY **Zip Code:** 40392-0707

Email: (if individual) Not Applicable

Phone: 502-627-2343

Technical Contact

Name: Kevin Moore

Title: Air Programs Supervisor

Mailing Address:
Street or P.O. Box: 4775 Lexington Road, P.O. Box 707
City: Winchester **State:** KY **Zip Code:** 40392-0707

Email: kevin.moore@ekpc.coop

Phone: 859-745-4157 ext. 6221

Air Permit Contact for Source

Name: Jerry Purvis

Title: Vice President, Environmental Affairs

Mailing Address:
Street or P.O. Box: Same
City: **State:** **Zip Code:**

Email: jerry.purvis@ekpc.coop

Phone: 859-744-4812

Section AI.3: Owner Information

☑ **Owner same as applicant**

Name: ____________________

Title: ____________________

Mailing Address: **Street or P.O. Box:** ____________________
City: __________ **State:** __________ **Zip Code:** __________

Email: ____________________

Phone: ____________________

List names of owners and officers of the company who have an interest in the company of 5% or more.

Name	Position

Section AI.4: Type of Application

Current Status: ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ General Permit ☐ Registration ☐ None

Requested Action: *(check all that apply)*

☐ Name Change	☐ Initial Registration	☑ Significant Revision	☐ Administrative Permit Amendment
☐ Renewal Permit	☐ Revised Registration	☐ Minor Revision	☐ Initial Source-wide Operating Permit
☐ 502(b)(10)Change	☐ Extension Request	☑ Addition of New Facility	☐ Portable Plant Relocation Notice
☐ Revision	☐ Off Permit Change	☐ Landfill Alternate Compliance Submittal	☑ Modification of Existing Facilities
☐ Ownership Change	☐ Closure		

Requested Status: ☑ Title V ☐ Conditional Major ☐ State-Origin ☑ PSD ☐ NSR ☐ Other: ____________

Is the source requesting a limitation of potential emissions? ☑ Yes ☐ No

Pollutant:	Requested Limit:	Pollutant:	Requested Limit:
☐ Particulate Matter		☐ Single HAP	
☐ Volatile Organic Compounds (VOC)		☐ Combined HAPs	
☐ Carbon Monoxide		☐ Air Toxics (40 CFR 68, Subpart F)	
☐ Nitrogen Oxides		☐ Carbon Dioxide	
☑ Sulfur Dioxide	39 tpy from Cooper Project	☐ Greenhouse Gases (GHG)	
☐ Lead		☐ Other	

For New Construction:

Proposed Start Date of Construction: *(MM/YYYY)* 01/2027

Proposed Operation Start-Up Date: *(MM/YYYY)* 02/2030

For Modifications:

Proposed Start Date of Modification: *(MM/YYYY)* 02/2028

Proposed Operation Start-Up Date: *(MM/YYYY)* 05/2029

Applicant is seeking coverage under a permit shield. ☑ Yes ☐ No

Identify any non-applicable requirements for which permit shield is sought on a separate attachment to the application.

Section AI.5 Other Required Information

Indicate the documents attached as part of this application:

- [x] DEP7007A Indirect Heat Exchangers and Turbines
- [x] DEP7007B Manufacturing or Processing Operations
- [ ] DEP7007C Incinerators and Waste Burners
- [ ] DEP7007F Episode Standby Plan
- [x] DEP7007J Volatile Liquid Storage
- [ ] DEP7007K Surface Coating or Printing Operations
- [ ] DEP7007L Mineral Processes
- [ ] DEP7007M Metal Cleaning Degreasers
- [x] DEP7007N Source Emissions Profile
- [ ] DEP7007P Perchloroethylene Dry Cleaning Systems
- [ ] DEP7007R Emission Offset Credit
- [ ] DEP7007S Service Stations
- [ ] DEP7007T Metal Plating and Surface Treatment Operations
- [x] DEP7007V Applicable Requirements and Compliance Activities
- [ ] DEP7007Y Good Engineering Practice and Stack Height Determination
- [ ] DEP7007AA Compliance Schedule for Non-complying Emission Units
- [ ] DEP7007BB Certified Progress Report
- [ ] DEP7007CC Compliance Certification RY23 DEP7007CC Form on file with KDAQ
- [x] DEP7007DD Insignificant Activities
- [x] DEP7007EE Internal Combustion Engines
- [ ] DEP7007FF Secondary Aluminum Processing
- [x] DEP7007GG Control Equipment
- [x] DEP7007HH Haul Roads
- [ ] Confidentiality Claim
- [ ] Ownership Change Form
- [ ] Secretary of State Certificate
- [x] Flowcharts or diagrams depicting process
- [ ] Digital Line Graphs (DLG) files of buildings, roads, etc.
- [x] Site Map
- [x] Map or drawing depicting location of facility
- [ ] Safety Data Sheet (SDS)
- [ ] Emergency Response Plan
- [x] Other: Application Report
  Acid Rain Permit Application

Section AI.6: Signature Block

I, the undersigned, hereby certify under penalty of law, that I am a responsible official*, and that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

Jerry Purvis	1/27/2025
Authorized Signature	**Date**
Jerry Purvis	Vice President, Environmental Affairs
Type or Printed Name of Signatory	**Title of Signatory**

*Responsible official as defined by 401 KAR 52:001.

Section AI.7: Notes, Comments, and Explanations
Clarification of AI.1 Permits/Registrations: Kentucky Division of Water KPDES Permit #KY 0003611 KY Division of Waste Management, Special Waste Landfill Permit (#SW 10000015) Division of Waste Management Certificate of Registration annual renewal KPDES Permit Renewal every five years

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007A
Indirect Heat Exchangers and Turbines

___ Section A.1: General Information
___ Section A.2: Operating and Fuel Information
___ Section A.3: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.

____ Manufacturer's specifications

Source Name: East Kentucky Power Cooperative, Inc.
KY EIS (AFS) #: 21-161-00009
Permit #: V-18-027
Agency Interest (AI) ID: 3808
Date: 1/24/2025

Section A.1: General Information

Emission Unit #	Emission Unit Name	Process ID	Process Name	Identify General Type: Indirect Heat Exchanger, Gas Turbine, or Combustion Turbine	Indirect Heat Exchanger Configuration	Manufacturer	Model No./ Serial No.	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	SCC Code	SCC Units	Control Device ID	Stack ID
EU 18	Unit 3 Gas Turbine	01	Natural Gas Firing in CT	Gas Turbine	na	Siemens 5000F		01/2027	20100201	MMcf	U3-C1 & U3-C2	S-U3
		02	No. 2 FO Firing in CT						20100101	Mgal	U3-C1 & U3-C2	S-U3
		03	Cold Startup Events on Natural Gas						39999993	Event	N/A	S-U3
		04	Warm Startup Events on Natural Gas						39999993	Event	N/A	S-U3
		05	Hot Startup Events on Natural Gas						39999993	Event	N/A	S-U3
		06	Shutdown Events on Natural Gas						39999993	Event	N/A	S-U3
		07	Cold Startup Events on Fuel Oil						39999993	Event	N/A	S-U3
		08	Warm Startup Events on Fuel Oil						39999993	Event	N/A	S-U3
		09	Hot Startup Events on Fuel Oil						39999993	Event	N/A	S-U3

Emission Unit #	Emission Unit Name	Process ID	Process Name	Identify General Type: Indirect Heat Exchanger, Gas Turbine, or Combustion Turbine	Indirect Heat Exchanger Configuration	Manufacturer	Model No./ Serial No.	Proposed/Actual Date of Construction Commencement (MM/YYYY)	SCC Code	SCC Units	Control Device ID	Stack ID
		10	Shutdown Events on Fuel Oil						39999993	Event	N/A	S-U3
EU 19	Unit 4 Gas Turbine	01	Natural Gas Firing in CT	Gas Turbine	na	Siemens 5000F		01/2027	20100201	MMcf	U4-C1 & U4-C2	S-U4
		02	No. 2 FO Firing in CT						20100101	Mgal	U4-C1 & U4-C2	S-U4
		03	Cold Startup Events on Natural Gas						39999993	Event	N/A	S-U4
		04	Warm Startup Events on Natural Gas						39999993	Event	N/A	S-U4
		05	Hot Startup Events on Natural Gas						39999993	Event	N/A	S-U4
		06	Shutdown Events on Natural Gas						39999993	Event	N/A	S-U4
		07	Cold Startup Events on Fuel Oil						39999993	Event	N/A	S-U4
		08	Warm Startup Events on Fuel Oil						39999993	Event	N/A	S-U4
		09	Hot Startup Events on Fuel Oil						39999993	Event	N/A	S-U4
		10	Shutdown Events on Fuel Oil						39999993	Event	N/A	S-U4

Emission Unit #	Emission Unit Name	Process ID	Process Name	Identify General Type: Indirect Heat Exchanger, Gas Turbine, or Combustion Turbine	Indirect Heat Exchanger Configuration	Manufacturer	Model No./ Serial No.	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	SCC Code	SCC Units	Control Device ID	Stack ID
EU 20	NG-Fired Auxiliary Boiler	01	Natural Gas Firing	Indirect Heat Exchanger	Boiler	TBD, 78.32 MMBtu/hr		01/2027	10200602	MMcf	N/A	S-20
EU 17	NG-Fired Dew Point Heater No. 1	01	Natural Gas Firing	Indirect Heat Exchanger	Process Heater	TBD, 11.65 MMBtu/hr		02/2028	39990003	MMcf	N/A	S-17
EU 23	NG-Fired Dew Point Heater No. 2	01	Natural Gas Firing	Indirect Heat Exchanger	Process Heater	TBD, 9.13 MMBtu/hr		01/2027	39990003	MMcf	N/A	S-23
EU 24	NG-Fired Dew Point Heater No. 3	01	Natural Gas Firing	Indirect Heat Exchanger	Process Heater	TBD, 9.13 MMBtu/hr		01/2027	39990003	MMcf	N/A	S-24
EU 2n	Indirect Heat Exchanger #2	01	Pulverized Coal	Indirect Heat Exchanger	na	TBD, 2,364 MMBtu/hr		10/1969	10100202	Tons	N/A	N/A
		~~02~~	~~Coal/Wood Waste Blend~~			~~N/A~~		~~10/28/1969~~	~~10200902~~	~~Tons~~	~~N/A~~	~~N/A~~
		03	Natural Gas			TBD, 2,433 MMBtu/hr		02/2028	10100601	MMcf	N/A	N/A
EU 29A/29B	Indirect-fired HVAC Heaters	01	Natural Gas Firing	Indirect Heat Exchanger	HVAC Heater	TBD, 39.35 MMBtu/hr Total		01/2027	39990003	MMcf	N/A	N/A

Section A.2: Operating and Fuel Information

Emission Unit #	If multipurpose unit, identify the percentage of use by purpose: Space Heat	Process Heat	Power	Emergency	Rated Capacity Heat Input *(MMBTU/hr)*	Rated Capacity Power Output	*(Specify units: hp, MW, or lb steam/hr)*	Describe Operating Scenario (only if this unit will be used in different configurations)	Classify Fuel as Primary or Secondary	Identify Fuel Type: Coal, Natural Gas, Wood, Biomass, Landfill/Digester Gas, Fuel Oil # (specify 1-6), or Other	Heat Content (HHV)	*(Specify units: Btu/lb, Btu/gal, or Btu/scf)*	Maximum Operating Hours	Ash Content *(%)*	Sulfur Content *(%)*
EU 18	0	0	100	na	2,734	~775	MW Net (Combined)	Refer to Section 4 in Appendix B of application.	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
					2,597			Refer to Section 4 in Appendix B of application.	Secondary	Fuel Oil	136	MMBtu/Mgal	1,080	na	0.0015 %
EU 19	0	0	100	na	2,734			Refer to Section 4 in Appendix B of application.	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
					2,597			Refer to Section 4 in Appendix B of application.	Secondary	Fuel Oil	136	MMBtu/Mgal	1,080	na	0.0015 %
EU 20	0	100	0	na	78.32	na	na	na	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
EU 17	0	100	0	na	11.65	na	na	na	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
EU 23	0	100	0	na	9.13	na	na	na	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
EU 24	0	100	0	na	9.13	na	na	na	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
EU 2n	0	0	100	na	2,364	240	MWg	Refer to Section 21 in Appendix B of application.	Primary	Pulverized Coal	12,660	Btu/lb	1,773	12.00	2.26
					~~na~~	~~na~~	~~MWg~~	~~na~~	~~Secondary~~	~~Wood Waste~~	~~na~~	~~MMBtu/ton~~	~~8,760~~	~~na~~	~~na~~
					2,433	240	MWg	Refer to Section 21 in Appendix B of application.	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf
EU 29A/29B	100	0	0	na	39.4	na	na	na	Primary	Natural Gas	1,060	Btu/scf	8,760	na	0.5 gr/Ccf

Section A.3: Notes, Comments, and Explanations

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007B

Manufacturing or Processing Operations

___ Section B.1: Process Information
___ Section B.2: Materials and Fuel Information
___ Section B.3: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.
___ Attach a flow diagram
___ Attach SDS

Source Name: East Kentucky Power Cooperative, Inc.
KY EIS (AFS) #: 21- 161-00009
Permit #: V-18-027
Agency Interest (AI) ID: 3808
Date: 1/24/2025

Section B.1: Process Information

Emission Unit #	Emission Unit Name	Describe Emission Unit	Process ID	Process Name	Manufacturer	Model No.	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Is the Process **Continuous** or **Batch**?	Number of Batches per 24 Hours *(if applicable)*	Hours per Batch *(if applicable)*
EU 25	One Mechanical Draft Cooling Tower, 9 Cells		01	Recirculating Water	na	na	01/2027	Continuous	na	na
EU 30	Three (3) Turbine Circuit Breakers with 30 lb. SF6 Circuits		01	SF6 Releases	na	na	01/2027	Continuous	na	na
EU 31	Twelve (12) Switchyard/Station Circuit Breakers each with 58 lb. SF6 Circuits		01	SF6 Releases	na	na	01/2027	Continuous	na	na

Emission Unit #	Emission Unit Name	Describe Emission Unit	Process ID	Process Name	Manufacturer	Model No.	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Is the Process **Continuous** or **Batch**?	Number of Batches per 24 Hours *(if applicable)*	Hours per Batch *(if applicable)*
EU 33	Natural Gas Piping Fugitives		01	Natural Gas Piping Fugitives - GV Valves	na	na	01/2027	Continuous	na	na
EU 33	Natural Gas Piping Fugitives		02	Natural Gas Piping Fugitives - Relief Valves	na	na	01/2027	Continuous	na	na
EU 33	Natural Gas Piping Fugitives		03	Natural Gas Piping Fugitives - Flanges	na	na	01/2027	Continuous	na	na
EU 33	Natural Gas Piping Fugitives		04	Natural Gas Piping Fugitives - Sampling Connections	na	na	01/2027	Continuous	na	na

Section B.2: Materials and Fuel Information

**Maximum yearly fuel usage rate only applies if applicant request operating restrictions through federally enforceable limitations.*

Emission Unit #	Emission Unit Name	Name of Raw Materials Input	Maximum Quantity of Each Raw Material Input		Total Process Weight Rate for Emission Unit	Name of Finished Materials	Maximum Quantity of Each Finished Material Output		Fuel Type	Maximum Hourly Fuel Usage Rate		Maximum Yearly Fuel Usage Rate		Sulfur Content	Ash Content
				(Specify Units/hr)	*(tons/hr)*			*(Specify Units/hr)*			*(Specify Units)*		*(Specify Units)*	*(%)*	*(%)*
EU 25	CCGT Cooling Tower	Cooling Water	9.95	MMgal/hr	na	na	na	na	na	na	na	na	na	na	na
EU 30	Turbine Circuit Breakers	SF6	30	lb/circuit	na	na	na	na	na	na	na	na	na	na	na
EU 31	Switchyard/Station Circuit Breakers	SF6	58	lb/circuit	na	na	na	na	na	na	na	na	na	na	na
EU 33	Natural Gas Piping Fugitives	Natural Gas	na	na	na	na	na	na	na	na	na	na	na	na	na

Section B.3: Notes, Comments, and Explanations

Section B.3: Notes, Comments, and Explanations
While not process operations, the SF6-containing circuit breakers and natural gas pipeline equipment leak components are included on this DEP7007B form to comprehensively represent all new emissions sources on required DEP7007 series forms.

Division for Air Quality 300 Sower Boulevard Frankfort, KY 40601 (502) 564-3999

DEP7007J

Volatile Liquid Storage

___ Section J.1: General Information

___ Section J.2: Tank Description

___ Section J.3: Gasoline Plants and Terminals

___ Section J.4: Loading Rack(s)

___ Section J.5: Equipment Leaks

___ Section J.6: Notes, Comments, and Explanations

Additional Documentation
___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG. ___ SDS attached

Source Name: East Kentucky Power Cooperative, Inc.

KY EIS (AFS) #: 21- 161-00009

Permit #: V-18-027

Agency Interest (AI) ID: 3808

Date: 1/24/2025

Section J.1: General Information

Emission Unit #	Emission Unit Name	Emission Unit Description	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Date of modification/ reconstruction	Control Device ID	Stack ID
26A	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs	Jan-27	na	na	S-26A
26B	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs	Jan-27	na	na	S-26B
27	1,000 gallon Diesel Storage Tank	1,000 gallon Diesel Storage Tank	Jan-27	na	na	S-27
28	350 gallon Diesel Storage Tank	350 gallon Diesel Storage Tank	Jan-27	na	na	S-28
34	93% Sulfuric Acid Tank	93% Sulfuric Acid Tank	Jan-27	na	na	IA-30

Section J.2: Tank Description

Emission Point #: EU26A

Emission Point Name: 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs

Tank ID#: EU26A; EQPT0022

Date Installed: Jan-27

List Applicable Regulations: 401 KAR 63:020; 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	20,590,514	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 57.78 deg. F		Tank Stock True Vapor Pressure = 0.0066 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 1,658,213

Shell Height/ Length: *(ft)* 40

Shell Diameter: *(ft)* 84

Tank Turnovers per Year: 12.42

Tank Orientation: ☐ Horizontal ☑ Vertical

If Vertical, provide Maximum Liquid Height: *(ft)* 37.5

Average Liquid Height: *(ft)* 35

Shell Color/Shade: ☐ Red ☐ White ☑ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Roof Color: ☐ Slack ☐ White ☑ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ☐ Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type:	☑ Dome	☐ Flat	☐ Cone	**Dome/Cone Height:**	11.5 ft	**Average Vapor Space Height:**	Unknown ft
Is Tank Underground?:	☐ Yes	☑ No		**Roof Condition:**	☑ Good ☐ Poor	**Vacuum Setting:**	-0.036 psig
Is Tank Heated?:	☐ Yes	☑ No		**Shell Condition:**	☑ Good ☐ Poor	**Pressure Setting:**	0.036 psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description: ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal ☐ Shoe Mounted
☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal ☐ Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined **External Shell Condition:** ☐ Good ☐ Poor

Roof Paint Condition: ☐ Good ☐ Poor **Self Supporting Roof?** ☐ Yes ☐ No

Number of Support Columns: ____________ **Effective Column Diameter:** _____ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Seam: ____________________ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well ☐ Vacuum Breaker
☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain ☐ Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:	☐ Vapor Mounted Primary	☐ Vapor Mounted Primary Rim Secondary Seal	☐ Vapor Mounted Prmary with Weather Shield
	☐ Liquid Mounted Primary	☐ Liquid Mounted Primary Rim Secondary Seal	☐ Liquid Mounted Primary with Weather Shield
	☐ Shoe Mounted Primary	☐ Shoe Mounted Primary Rim Secondary Seal	☐ Shoe Mounted Primary Shoe Secondary
Internal Shell Condition:	☐ Light Rust	☐ Dense Rust	☐ Gunite-lined
Tank Type:	☐ Riveted	☐ Welded	
Roof Type:	☐ Pontoon Roof	☐ Double Deck Roof	

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:	☐ Access Hatch	☐ Gauge Hatch	☐ Sample Well	☐ Roof Leg	☐ Vacuum Breaker
	☐ Guide Pole	☐ Gauge Float	☐ Roof Drain	☐ Rim Vent	☐ Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal capacity) (lb/1000 gal thru)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSFO	Breathing Losses	0.233	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSFO	Working Losses	0.021	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EU26B

Emission Point Name: 1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs

Tank ID#: EU26B; EQPT0023

Date Installed: Jan-27

List Applicable Regulations: 401 KAR 63:020; 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	20,590,514	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 57.78 deg. F		Tank Stock True Vapor Pressure = 0.0066 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 1,658,213

Shell Height/ Length: *(ft)* 40

Shell Diameter: *(ft)* 84

Tank Turnovers per Year: 12.42

Tank Orientation: ☐ Horizontal ☑ Vertical

If Vertical, provide Maximum Liquid Height: *(ft)* 37.5

Average Liquid Height: *(ft)* 35

Shell Color/Shade: ☐ Red ☐ White ☑ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Roof Color: ☐ Slack ☐ White ☑ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ☐ Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type: ☑ Dome ☐ Flat ☐ Cone

Dome/Cone Height: 11.5 ft

Average Vapor Space Height: Unknown ft

Is Tank Underground?: ☐ Yes ☑ No

Roof Condition: ☑ Good ☐ Poor

Vacuum Setting: -0.036 psig

Is Tank Heated?: ☐ Yes ☑ No

Shell Condition: ☑ Good ☐ Poor

Pressure Setting: 0.036 psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description: ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal ☐ Shoe Mounted ☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal ☐ Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

External Shell Condition: ☐ Good ☐ Poor

Roof Paint Condition: ☐ Good ☐ Poor

Self Supporting Roof? ☐ Yes ☐ No

Number of Support Columns: ____________

Effective Column Diameter: ______ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Seam: ____________________ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well ☐ Vacuum Breaker ☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain ☐ Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:

- ☐ Vapor Mounted Primary
- ☐ Liquid Mounted Primary
- ☐ Shoe Mounted Primary
- ☐ Vapor Mounted Primary Rim Secondary Seal
- ☐ Liquid Mounted Primary Rim Secondary Seal
- ☐ Shoe Mounted Primary Rim Secondary Seal
- ☐ Vapor Mounted Prmary with Weather Shield
- ☐ Liquid Mounted Primary with Weather Shield
- ☐ Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:

- ☐ Access Hatch
- ☐ Guide Pole
- ☐ Gauge Hatch
- ☐ Gauge Float
- ☐ Sample Well
- ☐ Roof Drain
- ☐ Roof Leg
- ☐ Rim Vent
- ☐ Vacuum Breaker
- ☐ Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal capacity) (lb/1000 gal thru)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSD	Breathing Losses	0.233	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSD	Working Losses	0.021	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EU27

Emission Point Name: 1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine

Tank ID#: EU27; EQPT0024

Date Installed: Jan-27

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	56,535	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 56.51 deg. F		Tank Stock True Vapor Pressure = 0.0060 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 1,000

Shell Height/ Length: *(ft)* 4.40

Shell Diameter: *(ft)* 8.80

Tank Turnovers per Year: 56.53

Tank Orientation: ☐ Horizontal ☑ Vertical

If Vertical, provide Maximum Liquid Height: *(ft)* 3.4

Average Liquid Height: *(ft)* 3.4

Shell Color/Shade: ☐ Red ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Roof Color: ☐ Slack ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ☐ Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type: ☑ Dome ☐ Flat ☐ Cone **Dome/Cone Height:** Unknown ft **Average Vapor Space Height:** Unknown ft

Is Tank Underground?: ☐ Yes ☑ No **Roof Condition:** ☑ Good ☐ Poor **Vacuum Setting:** -0.03 psig

Is Tank Heated?: ☐ Yes ☑ No **Shell Condition:** ☑ Good ☐ Poor **Pressure Setting:** 0.03 psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description: ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal ☐ Shoe Mounted

☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal ☐ Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined **External Shell Condition:** ☐ Good ☐ Poor

Roof Paint Condition: ☐ Good ☐ Poor **Self Supporting Roof?** ☐ Yes ☐ No

Number of Support Columns: ____________ **Effective Column Diameter:** ______ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Seam: ____________________ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well ☐ Vacuum Breaker

☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain ☐ Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
☐ Vapor Mounted Primary ☐ Vapor Mounted Primary Rim Secondary Seal ☐ Vapor Mounted Prmary with Weather Shield
☐ Liquid Mounted Primary ☐ Liquid Mounted Primary Rim Secondary Seal ☐ Liquid Mounted Primary with Weather Shield
☐ Shoe Mounted Primary ☐ Shoe Mounted Primary Rim Secondary Seal ☐ Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
☐ Access Hatch ☐ Gauge Hatch ☐ Sample Well ☐ Roof Leg ☐ Vacuum Breaker
☐ Guide Pole ☐ Gauge Float ☐ Roof Drain ☐ Rim Vent ☐ Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal capacity)* *(lb/1000 gal thru)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSD	Breathing Losses	0.285	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSD	Working Losses	0.013	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EU28

Emission Point Name: 350 Gallon Diesel Storage Tank for Fire Pump Engine

Tank ID#: EU28; EQPT0025

Date Installed: Jan-27

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	7,966	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 56.51 deg. F		Tank Stock True Vapor Pressure = 0.0060 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 350

Shell Height/ Length: *(ft)* 3.10

Shell Diameter: *(ft)* 6.20

Tank Turnovers per Year: 22.76

Tank Orientation: ☐ Horizontal ☑ Vertical

If Vertical, provide Maximum Liquid Height: *(ft)* 2.1

Average Liquid Height: *(ft)* 2.1

Shell Color/Shade: ☐ Red ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Roof Color: ☐ Slack ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ☐ Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type:	☑ Dome	☐ Flat	☐ Cone	**Dome/Cone Height:**	Unknown ft			**Average Vapor Space Height:**	Unknown ft	
Is Tank Underground?:	☐ Yes	☑ No		**Roof Condition:**	☑ Good	☐ Poor		**Vacuum Setting:**	-0.03 psig	
Is Tank Heated?:	☐ Yes	☑ No		**Shell Condition:**	☑ Good	☐ Poor		**Pressure Setting:**	0.03 psig	

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description: ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal ☐ Shoe Mounted ☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal ☐ Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

External Shell Condition: ☐ Good ☐ Poor

Roof Paint Condition: ☐ Good ☐ Poor

Self Supporting Roof? ☐ Yes ☐ No

Number of Support Columns: ______________

Effective Column Diameter: ______ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Seam: ______________________ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well ☐ Vacuum Breaker ☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain ☐ Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
- ☐ Vapor Mounted Primary
- ☐ Liquid Mounted Primary
- ☐ Shoe Mounted Primary
- ☐ Vapor Mounted Primary Rim Secondary Seal
- ☐ Liquid Mounted Primary Rim Secondary Seal
- ☐ Shoe Mounted Primary Rim Secondary Seal
- ☐ Vapor Mounted Prmary with Weather Shield
- ☐ Liquid Mounted Primary with Weather Shield
- ☐ Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
- ☐ Access Hatch
- ☐ Guide Pole
- ☐ Gauge Hatch
- ☐ Gauge Float
- ☐ Sample Well
- ☐ Roof Drain
- ☐ Roof Leg
- ☐ Rim Vent
- ☐ Vacuum Breaker
- ☐ Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal capacity)* *(lb/1000 gal thru)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSD	Breathing Losses	0.265	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSD	Working Losses	0.019	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EU34

Emission Point Name: 93% Sulfuric Acid Tank

Tank ID#: EU34; EQPT0031

Date Installed: Jan-27

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)* Minimum	Temperature *(°F)* Maximum	Vapor Pressure *(psia)* Minimum	Vapor Pressure *(psia)* Maximum
93% Sulfuric Acid	20,000	15.4	98.08 (H_2SO_4)	93% H_2SO_4 7% Water	Average Bulk Storage Temp = 56.51 deg. F		Tank Stock True Vapor Pressure = 9.78E-06 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 3,000

Shell Height/ Length: *(ft)* 6.34

Shell Diameter: *(ft)* 12.69

Tank Turnovers per Year: 6.67

Tank Orientation: ☐ Horizontal ☑ Vertical

If Vertical, provide Maximum Liquid Height: *(ft)* 5.3

Average Liquid Height: *(ft)* 5.3

Shell Color/Shade: ☐ Red ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Roof Color: ☐ Slack ☑ White ☐ Light Gray ☐ Medium Gray ☐ Aluminum Specular ☐ Aluminum Diffuse ☐ Other: ______

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof ☐ Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type:	☑ Dome ☐ Flat ☐ Cone	**Dome/Cone Height:**	Unknown ft	**Average Vapor Space Height:**	Unknown ft
Is Tank Underground?:	☐ Yes ☑ No	**Roof Condition:**	☑ Good ☐ Poor	**Vacuum Setting:**	-0.03 psig
Is Tank Heated?:	☐ Yes ☑ No	**Shell Condition:**	☑ Good ☐ Poor	**Pressure Setting:**	0.03 psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description: ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal ☐ Shoe Mounted ☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal ☐ Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

External Shell Condition: ☐ Good ☐ Poor

Roof Paint Condition: ☐ Good ☐ Poor

Self Supporting Roof? ☐ Yes ☐ No

Number of Support Columns: ____________

Effective Column Diameter: ______ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Seam: ____________________ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well ☐ Vacuum Breaker ☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain ☐ Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
☐ Vapor Mounted Primary ☐ Vapor Mounted Primary Rim Secondary Seal ☐ Vapor Mounted Prmary with Weather Shield
☐ Liquid Mounted Primary ☐ Liquid Mounted Primary Rim Secondary Seal ☐ Liquid Mounted Primary with Weather Shield
☐ Shoe Mounted Primary ☐ Shoe Mounted Primary Rim Secondary Seal ☐ Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
☐ Access Hatch ☐ Gauge Hatch ☐ Sample Well ☐ Roof Leg ☐ Vacuum Breaker
☐ Guide Pole ☐ Gauge Float ☐ Roof Drain ☐ Rim Vent ☐ Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal capacity) (lb/1000 gal thru)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	H_2SO_4	Breathing Losses	6.77E-05	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	H_2SO_4	Working Losses	4.46E-06	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.6: Notes, Comments, and Explanations

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007N

Source Emissions Profile

__ Section N.1: Emission Summary
__ Section N.2: Stack Information
__ Section N.3: Fugitive Information
__ Section N.4: Notes, Comments, and Explanations

Additional Documentation

__ Complete DEP7007AI

Source Name: East Kentucky Power Cooperative, Inc.
KY EIS (AFS) #: 21- 161-00009
Permit #: V-18-027
Agency Interest (AI) ID: 3808
Date: 1/24/2025

N.1: Emission Summary

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas															
		01	Pulverized Coal					SCC Code: 10100202					SCC Units: Tons Bituminous Coal Burned			
				LNB & SCR	N/A	N/A	93.4	NOX	10.7	AP-42, Table 1.1-3	N/A	81.09%	1,000	189	4,381	828
				GCP	N/A	N/A	93.4	CO	0.487	AP-42, Table 1.1-3	N/A	N/A	45.5	45.5	199	199
				GCP	N/A	N/A	93.4	VOC	0.058	AP-42, Table 1.1-19	N/A	N/A	5.46	5.46	23.9	23.9
				PJFF	N/A	N/A	93.4	PM-TOT	117	PM-FIL: AP-42, Table 1.1-4; PM-CON: AP-42, Table 1.1-5	N/A	99.35%	10,958	70.9	47,996	311
				PJFF	N/A	N/A	93.4	PM10-TOT	108	PM-FIL x cumulative mass fraction from AP-42, Table 1.1-6; Includes PM-CON	N/A	99.32%	10,085	69.0	44,173	302
				PJFF	N/A	N/A	93.4	PM2.5-TOT	62.4	PM-FIL x cumulative mass fraction from AP-42, Table 1.1-6; Includes PM-CON	N/A	98.97%	5,830	59.8	25,535	262
				DFGD	N/A	N/A	93.4	SO2	83.6	AP-42 Table 1.1-3	N/A	96.97%	7,808	236	34,201	1,035
				Low Sulfur Fuel, Ammonia Slip	N/A	N/A	93.4	H2SO4	0.127	Conversion in boiler & SCR w/ reduction by NH3 slip and F-factors for APH and WFGD+BH	N/A	N/A	11.9	11.9	51.9	51.9
				PJFF	N/A	N/A	93.4	Lead	0.013	AP-42 Tab 1.1-17	N/A	99.74%	1.20	3.12E-03	5.25	0.014
				GCP	N/A	N/A	93.4	CO2	5,207	40 CFR 98, Subpart C, Table C-1 for Bituminous Coal	N/A	N/A	486,150	486,150	2,129,337	2,129,337
				GCP	N/A	N/A	93.4	CH4	0.614	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)	N/A	N/A	57.3	57.3	251	251
				GCP	N/A	N/A	93.4	N2O	0.089	40 CFR 98, Subpart C, Table C-2 for Coal and Coke (all fuel types in Table C-1)	N/A	N/A	8.34	8.34	36.5	36.5
				N/A	N/A	N/A	93.4	CO2e	5,248	(CO2 EF) + (CH4 EF * 28 CH4 GWP) + (N2O EF * 265 N2O GWP)	N/A	N/A	489,965	489,965	2,146,047	2,146,047

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
				N/A	N/A	N/A	93.4	NH3	0.239	Avg of typical ammonia slip of 6 ppmvd @6% O2 and Method 19	N/A	N/A	22.3	22.3	97.7	97.7
				N/A	N/A	N/A	93.4	Benzene	1.27E-03	AP-42 Tab 1.1-14	N/A	N/A	0.118	0.118	0.518	0.518
				N/A	N/A	N/A	93.4	Cyanide Compounds	2.43E-03	AP-42 Tab 1.1-14	N/A	N/A	0.227	0.227	0.996	0.996
				N/A	N/A	N/A	93.4	Formaldehyde	2.34E-04	AP-42 Tab 1.1-14	N/A	N/A	0.022	0.022	0.096	0.096
				N/A	N/A	N/A	93.4	Hexane	6.52E-05	AP-42 Tab 1.1-14	N/A	N/A	6.09E-03	6.09E-03	0.027	0.027
				DFGD	N/A	N/A	93.4	Hydrogen Chloride	1.17	AP-42 Tab 1.1-14	N/A	98.12%	109	2.05	478	8.98
				DFGD	N/A	N/A	93.4	Hydrogen Fluoride	0.146	AP-42 Tab 1.1-14	N/A	98.12%	13.6	0.256	59.7	1.12
				N/A	N/A	N/A	93.4	Toluene	2.34E-04	AP-42 Tab 1.1-14	N/A	N/A	0.022	0.022	0.096	0.096
				PJFF	N/A	N/A	93.4	Arsenic	0.017	AP-42 Tab 1.1-17	N/A	99.74%	1.62	4.20E-03	7.08	0.018
				PJFF	N/A	N/A	93.4	Cadmium	1.12E-03	AP-42 Tab 1.1-17	N/A	99.74%	0.105	2.73E-04	0.460	1.20E-03
				PJFF	N/A	N/A	93.4	Chromium	0.036	AP-42 Tab 1.1-17	N/A	99.74%	3.33	8.67E-03	14.6	0.038
				PJFF	N/A	N/A	93.4	Manganese	0.041	AP-42 Tab 1.1-17	N/A	99.74%	3.79	9.86E-03	16.6	0.043
				PJFF	N/A	N/A	93.4	Mercury	4.05E-04	AP-42 Tab 1.1-17	N/A	99.74%	0.038	9.83E-05	0.166	4.31E-04
				PJFF	N/A	N/A	93.4	Nickel	0.029	AP-42 Tab 1.1-17	N/A	99.74%	2.74	7.13E-03	12.0	0.031
				GCP	N/A	N/A	93.4	Total HAP	0.029	Sum of HAPs	N/A	N/A	2.74	2.74	12.0	12.0
		02	Coal/Wood Waste Blend					SCC Code: 10200902					SCC Units: Tons Wood/Bark Burned			
		Please remove EU 2n, Process ID 02														
		03	Natural Gas					SCC Code: 10100601					SCC Units: Million Cubic Feet Natural Gas Burned			
				LNB & SCR	N/A	N/A	2.30	NOX	291	AP-42 Table 1.4-1	N/A	70.86%	668	195	2,925	853
				GCP	N/A	N/A	2.30	CO	127	AP-42 Table 1.4-1	N/A	N/A	292	292	1,279	1,279
				GCP	N/A	N/A	2.30	VOC	5.72	AP-42 Section 1.4 Table 1.4-2	N/A	N/A	13.1	13.1	57.5	57.5
				PJFF	N/A	N/A	2.30	PM-TOT	3.61	AP-42 Table 1.4-2 + EPA Speciate Database	N/A	N/A	8.28	8.28	36.3	36.3
				PJFF	N/A	N/A	2.30	PM10-TOT	3.61	= PM10-FIL + PM-CON	N/A	N/A	8.28	8.28	36.3	36.3
				PJFF	N/A	N/A	2.30	PM2.5-TOT	3.61	= PM2.5-FIL + PM-CON	N/A	N/A	8.28	8.28	36.3	36.3
				DFGD	N/A	N/A	2.30	SO2	1.43	Pipeline spec conversion	N/A	N/A	3.28	3.28	14.3	14.3
				Low Sulfur Fuel, Ammonia Slip	N/A	N/A	2.30	H2SO4	0.011	1.531% conversion of SO2 to H2SO4 and 0.5 F2 for Air Preheater	N/A	N/A	0.025	0.025	0.110	0.110
				PJFF	N/A	N/A	2.30	Lead	5.20E-04	AP-42, Section 1.4, Table 1.4-2	N/A	N/A	1.19E-03	1.19E-03	5.22E-03	5.22E-03
				GCP	N/A	N/A	2.30	CO2	123,996	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu	N/A	N/A	284,620	284,620	1,246,635	1,246,635
				GCP	N/A	N/A	2.30	CH4	2.34	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu	N/A	N/A	5.36	5.36	23.5	23.5
				GCP	N/A	N/A	2.30	N2O	0.234	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu	N/A	N/A	0.536	0.536	2.35	2.35
				N/A	N/A	N/A	2.30	Benzene	2.10E-03	AP-42 Table 1.4-3	N/A	N/A	4.82E-03	4.82E-03	0.021	0.021
				N/A	N/A	N/A	2.30	Dichlorobenzene	1.20E-03	AP-42 Table 1.4-3	N/A	N/A	2.75E-03	2.75E-03	0.012	0.012
				N/A	N/A	N/A	2.30	Formaldehyde	0.075	AP-42 Table 1.4-3	N/A	N/A	0.172	0.172	0.754	0.754
				N/A	N/A	N/A	2.30	Hexane	1.80	AP-42 Table 1.4-3	N/A	N/A	4.13	4.13	18.1	18.1
				N/A	N/A	N/A	2.30	Naphthalene	6.10E-04	AP-42 Table 1.4-3	N/A	N/A	1.40E-03	1.40E-03	6.13E-03	6.13E-03

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	N/A	2.30	Toluene	3.40E-03	AP-42 Table 1.4-3	N/A	N/A	7.80E-03	7.80E-03	0.034	0.034
				N/A	N/A	N/A	2.30	Arsenic	2.00E-04	AP-42 Table 1.4-4	N/A	N/A	4.59E-04	4.59E-04	2.01E-03	2.01E-03
				N/A	N/A	N/A	2.30	Cadmium	1.10E-03	AP-42 Table 1.4-4	N/A	N/A	2.52E-03	2.52E-03	0.011	0.011
				N/A	N/A	N/A	2.30	Chromium	1.40E-03	AP-42 Table 1.4-4	N/A	N/A	3.21E-03	3.21E-03	0.014	0.014
				N/A	N/A	N/A	2.30	Manganese	3.80E-04	AP-42 Table 1.4-4	N/A	N/A	8.72E-04	8.72E-04	3.82E-03	3.82E-03
				N/A	N/A	N/A	2.30	Mercury	2.60E-04	AP-42 Table 1.4-4	N/A	N/A	5.97E-04	5.97E-04	2.61E-03	2.61E-03
				N/A	N/A	N/A	2.30	Nickel	2.10E-03	AP-42 Table 1.4-4	N/A	N/A	4.82E-03	4.82E-03	0.021	0.021
				GCP	N/A	N/A	2.30	Total HAP	1.89	Sum of HAPs	N/A	N/A	4.33	4.33	19.0	19.0
EU 3	Coal Handling Operations															
		01	Receiving Hopper No. 1					SCC Code: 30501008					SCC Units: Tons Coal Shipped			
	Process ID 1 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM10-TOT	1.89E-04	AP-42 Section 13.2.4	N/A	70.00%	0.010	3.00E-03	0.044	0.013
				||	N/A	N/A	52.9	PM2.5-TOT	2.86E-05	AP-42 Section 13.2.4	N/A	70.00%	1.52E-03	4.55E-04	6.64E-03	1.99E-03
		02	Crusher (Primary)					SCC Code: 30501010					SCC Units: Tons Coal Shipped			
	Process ID 2 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Appendix B, Table B.2.2 for Mechanically Generated Aggregate, Unprocessed Ores			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM10-TOT	1.02E-04	AP-42 Appendix B	N/A	70.00%	5.40E-03	1.62E-03	0.024	7.09E-03
				||	N/A	N/A	52.9	PM2.5-TOT	3.00E-05	AP-42 Appendix B	N/A	70.00%	1.59E-03	4.76E-04	6.95E-03	2.09E-03
		03	Convey & Transfer (5)					SCC Code: 30501011					SCC Units: Tons Coal Shipped			
	Process ID 3 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM10-TOT	1.42E-04	AP-42 Section 13.2.4	N/A	70.00%	7.51E-03	2.25E-03	0.033	9.87E-03
				||	N/A	N/A	52.9	PM2.5-TOT	2.15E-05	AP-42 Section 13.2.4	N/A	70.00%	1.14E-03	3.41E-04	4.98E-03	1.49E-03
		04	Reclaim Hopper					SCC Code: 30501011					SCC Units: Tons Coal Shipped			

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
	Process ID 4 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM10-TOT	7.09E-04	AP-42 Section 13.2.4	N/A	70.00%	0.038	0.011	0.164	0.049
				||	N/A	N/A	52.9	PM2.5-TOT	1.07E-04	AP-42 Section 13.2.4	N/A	70.00%	5.69E-03	1.71E-03	0.025	7.47E-03
		05	Stockpile					SCC Code: 30501009					SCC Units: Tons Coal Shipped			
	Process ID 5 emission factors have been derived from EPA's Guidance Document "Control of Open Fugitive Dust Sources"			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM-TOT	6.14E-03	Control of Open Fugitive Dust Sources; EPA-450/3-88-008, September 1988, Page 4-17, Equation 2	N/A	70.00%	0.325	0.098	1.42	0.427
				||	N/A	N/A	52.9	PM10-TOT	2.91E-03	Control of Open Fugitive Dust Sources; EPA-450/3-88-008, September 1988, Page 4-17, Equation 2	N/A	70.00%	0.154	0.046	0.673	0.202
				||	N/A	N/A	52.9	PM2.5-TOT	4.40E-04	Control of Open Fugitive Dust Sources; EPA-450/3-88-008, September 1988, Page 4-17, Equation 2	N/A	70.00%	0.023	6.98E-03	0.102	0.031
		06	Drop Pt into Bunkers					SCC Code: 30501011					SCC Units: Tons Coal Shipped			
	Process ID 6 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	52.9	PM10-TOT	7.09E-04	AP-42 Section 13.2.4	N/A	90.00%	0.038	3.75E-03	0.164	0.016
				||	N/A	N/A	52.9	PM2.5-TOT	1.07E-04	AP-42 Section 13.2.4	N/A	90.00%	5.69E-03	5.69E-04	0.025	2.49E-03
				||	N/A	N/A	52.9	PM-TOT	1.50E-03	Existing KyEIS Emission Factor	N/A	90.00%	0.079	7.94E-03	0.348	0.035
		07	Wood Waste Stockpile					SCC Code: 30700803					SCC Units: Tons Sawdust Processed			
										Please remove EU 3, Process ID 07						
		08	Wood Waste Storage					SCC Code: 30703002					SCC Units: Tons Wood Waste Processed			
										Please remove EU 3, Process ID 08						
		09	Unpaved Yard Area					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
	Process ID 9 PM, PM10, and PM2.5 emission factors have been derived from AP-42, Section 13.2.2 for Unpaved Roads			DusTreat CF9156 DusTreat DC6109I Additives to reduce fugitive emissions.	N/A	N/A	0.695	PM-TOT	5.20	AP-42 Section 13.2.2	N/A	70.00%	3.61	1.08	15.8	4.75
	Process ID 9 maximum hourly throughput has been revised to represent only vehicle traffic through the unpaved yard area.			||	N/A	N/A	0.695	PM10-TOT	1.34	AP-42 Section 13.2.2	N/A	70.00%	0.932	0.280	4.08	1.22
				||	N/A	N/A	0.695	PM2.5-TOT	0.134	AP-42 Section 13.2.2	N/A	70.00%	0.093	0.028	0.408	0.122

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
EU 7	Coal Crushing Facility															
		01	Reclaim Hopper					SCC Code: 30501010					SCC Units: Tons Coal Shipped			
	Process ID 1 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			N/A	N/A	N/A	52.9	PM10-TOT	1.89E-04	AP-42 Section 13.2.4	N/A	70.00%	0.010	3.00E-03	0.044	0.013
				N/A	N/A	N/A	52.9	PM2.5-TOT	2.86E-05	AP-42 Section 13.2.4	N/A	70.00%	1.52E-03	4.55E-04	6.64E-03	1.99E-03
		02	Crusher (Secondary)					SCC Code: 30501010					SCC Units: Tons Coal Shipped			
	Process ID 2 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Appendix B, Table B.2.2 for Mechanically Generated Aggregate, Unprocessed Ores			N/A	N/A	N/A	52.9	PM10-TOT	1.02E-04	AP-42 Appendix B	N/A	90.00%	5.40E-03	5.40E-04	0.024	2.36E-03
				N/A	N/A	N/A	52.9	PM2.5-TOT	3.00E-05	AP-42 Appendix B	N/A	90.00%	1.59E-03	1.59E-04	6.95E-03	6.95E-04
				N/A	N/A	N/A	52.9	PM-TOT	2.00E-04	Existing KyEIS Emission Factor	N/A	90.00%	0.011	1.06E-03	0.046	4.64E-03
		03	Convey & Transfer (4)					SCC Code: 30501010					SCC Units: Tons Coal Shipped			
	Process ID 1 speciated PM emission factors have been derived from the existing emission factor for total PM and AP-42 Section 13.2.4.			N/A	N/A	N/A	52.9	PM10-TOT	1.42E-04	AP-42 Section 13.2.4	N/A	90.00%	7.51E-03	7.51E-04	0.033	3.29E-03
				N/A	N/A	N/A	52.9	PM2.5-TOT	2.15E-05	AP-42 Section 13.2.4	N/A	90.00%	1.14E-03	1.14E-04	4.98E-03	4.98E-04
				N/A	N/A	N/A	52.9	PM-TOT	3.00E-04	Existing KyEIS Emission Factor	N/A	90.00%	0.016	1.59E-03	0.070	6.95E-03
EU 8	Emergency Generator, CAT 3516															
		01	Diesel Firing					SCC Code: 20100101					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
	PM emission factors have been derived based on AP-42, Table 3.4.2.			N/A	N/A	N/A	0.089	PM-TOT	9.55	AP-42, Table 3.4.2	N/A	N/A	0.849	0.849	0.212	0.212
				N/A	N/A	N/A	0.089	PM10-TOT	7.85	AP-42, Table 3.4.2	N/A	N/A	0.698	0.698	0.175	0.175
				N/A	N/A	N/A	0.089	PM2.5-TOT	7.62	AP-42, Table 3.4.2	N/A	N/A	0.677	0.677	0.169	0.169
EU 9-01	Fly Ash and Waste Product Silo C: 108,000 ft3 capacity															
		01	Fly Ash and Waste Silo #1					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-01	15.1	PM2.5-TOT	0.061	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	0.920	9.20E-03	4.03	0.040
		02	New Waste Product Silo #2					SCC Code: 30510298					SCC Units: Tons Material Processed			
		Please remove EU 09-01, Process ID 02														
EU 9-03	Vacuum Systems #1 & #2															
		01	Vacuum System #1					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-03	15.1	PM2.5-TOT	0.293	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	4.43	0.044	19.4	0.194
		02	Vacuum System #2					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-03	15.1	PM2.5-TOT	0.293	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	4.43	0.044	19.4	0.194
EU 9-04	Pebble Lime Silo															
		01	Pebble Lime Silo					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-04	7.17	PM2.5-TOT	0.309	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	2.21	0.022	9.70	0.097

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
EU 9-05	Pebble Lime Silo A & B															
		01	Hydrator Feed Bin #1					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-05	9.43	PM2.5-TOT	4.36E-03	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	0.041	4.11E-04	0.180	1.80E-03
		02	Hydrator Feed Bin #2					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-05	9.43	PM2.5-TOT	4.36E-03	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	0.041	4.11E-04	0.180	1.80E-03
EU 9-06	Lime Hydrator A & B															
		01	Lime Hydrator #1					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-06	7.17	PM2.5-TOT	0.084	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	0.602	6.02E-03	2.64	0.026
		02	Lime Hydrator #2					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-06	7.17	PM2.5-TOT	0.084	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	0.602	6.02E-03	2.64	0.026
EU 9-07	Hydrated Lime Silo															
		01	Hydrated Lime Silo					SCC Code: 30510298					SCC Units: Tons Material Processed			
				Fabric Filter	N/A	09-07	18.9	PM2.5-TOT	0.235	AP-42 Table B.2.2 Category: 5 Process: Calcining and Other Heat Reaction	N/A	99.00%	4.43	0.044	19.4	0.194
EU 9-08	Lime Dust Silo															
		01	Lime Dust Silo					SCC Code: 30510298					SCC Units: Tons Material Processed			
										Please remove EU 09-08, Process ID 01						
EU 10	Paved Roadways															
		01	Paved Haul Road					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
										Please remove EU 10, Process ID 01						
		02	New Haul Road					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
	Process ID 2 emission factors have been derived from AP-42, Section 13.2.1 for Paved Roads			Dust Suppression	N/A	N/A	0.979	PM-TOT	0.339	AP-42 Section 13.2.1	N/A	70.00%	0.331	0.099	1.45	0.436
				Dust Suppression	N/A	N/A	0.979	PM10-TOT	0.068	AP-42 Section 13.2.1	N/A	70.00%	0.066	0.020	0.290	0.087
				Dust Suppression	N/A	N/A	0.979	PM2.5-TOT	0.017	AP-42 Section 13.2.1	N/A	70.00%	0.016	4.88E-03	0.071	0.021
EU 14	Burnside Service Center: Ford LRG425															
		01	Liquid Propane Gas (LPG) Usage					SCC Code: 20301001					SCC Units: 1000 Gallons Liquified Petroleum Gas (LPG) Burn			
										Please remove EU 14, Process ID 01						
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)															
		01	Natural Gas Firing					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			
				N/A	N/A	S-17	0.011	NOX	50.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.571	0.571	2.50	2.50
				N/A	N/A	S-17	0.011	CO	84.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.960	0.960	4.20	4.20

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	S-17	0.011	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	0.063	0.063	0.275	0.275
				N/A	N/A	S-17	0.011	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.040	0.040	0.174	0.174
				N/A	N/A	S-17	0.011	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.040	0.040	0.174	0.174
				N/A	N/A	S-17	0.011	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.040	0.040	0.174	0.174
				N/A	N/A	S-17	0.011	SO2	1.43	Pipeline spec conversion	N/A	N/A	0.016	0.016	0.071	0.071
				N/A	N/A	S-17	0.011	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	1.25E-03	1.25E-03	5.47E-03	5.47E-03
				N/A	N/A	S-17	0.011	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	5.71E-06	5.71E-06	2.50E-05	2.50E-05
				N/A	N/A	S-17	0.011	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	1,371	1,371	6,005	6,005
				N/A	N/A	S-17	0.011	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	0.026	0.026	0.113	0.113
				N/A	N/A	S-17	0.011	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	2.58E-03	2.58E-03	0.011	0.011
				N/A	N/A	S-17	0.011	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	1,372	1,372	6,011	6,011
				N/A	N/A	S-17	0.011	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	2.40E-05	2.40E-05	1.05E-04	1.05E-04
				N/A	N/A	S-17	0.011	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	1.37E-05	1.37E-05	6.00E-05	6.00E-05
				N/A	N/A	S-17	0.011	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	8.57E-04	8.57E-04	3.75E-03	3.75E-03
				N/A	N/A	S-17	0.011	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	0.021	0.021	0.090	0.090
				N/A	N/A	S-17	0.011	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	6.97E-06	6.97E-06	3.05E-05	3.05E-05
				N/A	N/A	S-17	0.011	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	3.88E-05	3.88E-05	1.70E-04	1.70E-04
				N/A	N/A	S-17	0.011	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	2.28E-06	2.28E-06	1.00E-05	1.00E-05
				N/A	N/A	S-17	0.011	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	1.26E-05	1.26E-05	5.50E-05	5.50E-05
				N/A	N/A	S-17	0.011	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	1.60E-05	1.60E-05	7.00E-05	7.00E-05
				N/A	N/A	S-17	0.011	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	4.34E-06	4.34E-06	1.90E-05	1.90E-05
				N/A	N/A	S-17	0.011	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	2.97E-06	2.97E-06	1.30E-05	1.30E-05
				N/A	N/A	S-17	0.011	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	2.40E-05	2.40E-05	1.05E-04	1.05E-04
				N/A	N/A	S-17	0.011	Total HAP	1.89	Sum of HAPs	N/A	N/A	0.022	0.022	0.094	0.094
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST															
		01	Natural Gas Firing in CT					SCC Code: 20100201					SCC Units: Million Cubic Feet Natural Gas Burned			
				SCR	C1	S-U3	2.58	NOX	57.6	EKPC Calculated	N/A	86.67%	149	19.8	651	86.8
				CatOx	C1	S-U3	2.58	CO	9.36	EKPC Calculated	N/A	50.00%	24.1	12.1	106	52.9
				CatOx	C2	S-U3	2.58	VOC	1.91	EKPC Calculated	N/A	30.00%	4.94	3.46	21.6	15.1
				N/A	N/A	S-U3	2.58	PM-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U3	2.58	PM10-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U3	2.58	PM2.5-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U3	2.58	SO2	1.42	Pipeline spec conversion	N/A	N/A	3.67	3.67	16.1	16.1
				N/A	N/A	S-U3	2.58	H2SO4	2.18	Pipeline spec conversion	N/A	N/A	5.63	5.63	24.6	24.6
				N/A	N/A	S-U3	2.58	NH3	7.11	EKPC Requirement	N/A	N/A	18.3	18.3	80.4	80.4
				N/A	N/A	S-U3	2.58	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	309,584	309,584	1,355,978	1,355,978
				N/A	N/A	S-U3	2.58	CH4	24.9	AP-42, Table 3.1-2a	N/A	N/A	64.2	64.2	281	281
				N/A	N/A	S-U3	2.58	N2O	3.62	AP-42, Table 3.1-2a	N/A	N/A	9.34	9.34	40.9	40.9
				N/A	N/A	S-U3	2.58	CO2e	121,674	40 CFR 98 Subpart A	N/A	N/A	313,855	313,855	1,374,685	1,374,685
				CatOx	C2	S-U3	2.58	1,3-Butadiene	4.39E-04	AP-42 Table 3.1	N/A	30.00%	1.13E-03	7.92E-04	4.96E-03	3.47E-03
				CatOx	C2	S-U3	2.58	Acetaldehyde	0.256	AP-42 Table 3.1 & 3-4 of BID	N/A	30.00%	0.662	0.463	2.90	2.03
				CatOx	C2	S-U3	2.58	Acrolein	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	N/A	43.44%	0.017	9.52E-03	0.074	0.042
				CatOx	C2	S-U3	2.58	Benzene	0.012	AP-42 Table 3.1 & 3-4 of BID	N/A	72.83%	0.032	8.58E-03	0.138	0.038
				CatOx	C2	S-U3	2.58	Ethylbenzene	0.033	AP-42 Table 3.1	N/A	30.00%	0.084	0.059	0.369	0.258
				CatOx	C2	S-U3	2.58	Formaldehyde	0.724	EKPC Requirement	N/A	67.97%	1.87	0.598	8.18	2.62
				CatOx	C2	S-U3	2.58	Naphthalene	1.33E-03	AP-42 Table 3.1	N/A	30.00%	3.42E-03	2.39E-03	0.015	0.010
				CatOx	C2	S-U3	2.58	PAH	2.24E-03	AP-42 Table 3.1	N/A	30.00%	5.79E-03	4.05E-03	0.025	0.018
				CatOx	C2	S-U3	2.58	Propylene Oxide	0.030	AP-42 Table 3.1	N/A	30.00%	0.076	0.053	0.334	0.234
				CatOx	C2	S-U3	2.58	Toluene	0.133	AP-42 Table 3.1	N/A	30.00%	0.342	0.239	1.50	1.05
				CatOx	C2	S-U3	2.58	Xylenes	0.065	AP-42 Table 3.1	N/A	30.00%	0.168	0.118	0.738	0.516
				N/A	N/A	S-U3	2.58	Total HAP	1.26	Sum of HAPs	N/A	N/A	3.26	1.56	14.3	6.82
		02	No. 2 FO Firing in CT					SCC Code: 20100101					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
				SCR	C1	S-U3	19.1	NOX	13.5	EKPC Calculated	N/A	82.00%	257	46.3	139	25.0

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				SCR	C1	S-U3	19.1	CO	1.31	EKPC Calculated	N/A	50.00%	25.0	12.5	13.5	6.76
				CatOx	C2	S-U3	19.1	VOC	0.269	EKPC Calculated	N/A	30.00%	5.12	3.58	2.77	1.94
				N/A	N/A	S-U3	19.1	PM-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U3	19.1	PM10-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U3	19.1	PM2.5-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U3	19.1	SO2	0.207	ULSD spec conversion	N/A	N/A	3.94	3.94	2.13	2.13
				N/A	N/A	S-U3	19.1	H2SO4	0.316	ULSD spec conversion	N/A	N/A	6.03	6.03	3.26	3.26
				N/A	N/A	S-U3	19.1	NH3	0.998	EKPC Requirement	N/A	N/A	19.0	19.0	10.3	10.3
				N/A	N/A	S-U3	19.1	CO2	22,501	40 CFR 98, Table C-1	N/A	N/A	428,996	428,996	231,658	231,658
				N/A	N/A	S-U3	19.1	CH4	0.913	AP-42, Table 3.1-2a	N/A	N/A	17.4	17.4	9.40	9.40
				N/A	N/A	S-U3	19.1	CO2e	22,575	40 CFR 98 Subpart A	N/A	N/A	430,406	430,406	232,419	232,419
				CatOx	C2	S-U3	19.1	1,3-Butadiene	2.22E-03	AP42 Table 3.1-4	N/A	30.00%	0.042	0.030	0.023	0.016
				CatOx	C2	S-U3	19.1	Benzene	7.65E-03	AP42 Table 3.1-4	N/A	30.00%	0.146	0.102	0.079	0.055
				CatOx	C2	S-U3	19.1	Formaldehyde	0.030	EKPC Requirement	N/A	21.84%	0.568	0.444	0.307	0.240
				CatOx	C2	S-U3	19.1	Naphthalene	4.87E-03	AP42 Table 3.1-4	N/A	30.00%	0.093	0.065	0.050	0.035
				CatOx	C2	S-U3	19.1	PAH	5.56E-03	AP42 Table 3.1-4	N/A	30.00%	0.106	0.074	0.057	0.040
				N/A	N/A	S-U3	19.1	Arsenic	1.53E-03	AP42 Table 3.1-5	N/A	N/A	0.029	0.029	0.016	0.016
				N/A	N/A	S-U3	19.1	Beryllium	4.31E-05	AP42 Table 3.1-5	N/A	N/A	8.22E-04	8.22E-04	4.44E-04	4.44E-04
				N/A	N/A	S-U3	19.1	Cadmium	6.67E-04	AP42 Table 3.1-5	N/A	N/A	0.013	0.013	6.87E-03	6.87E-03
				N/A	N/A	S-U3	19.1	Chromium	1.53E-03	AP42 Table 3.1-5	N/A	N/A	0.029	0.029	0.016	0.016
				N/A	N/A	S-U3	19.1	Lead	1.95E-03	AP42 Table 3.1-5	N/A	N/A	0.037	0.037	0.020	0.020
				N/A	N/A	S-U3	19.1	Manganese	0.110	AP42 Table 3.1-5	N/A	N/A	2.09	2.09	1.13	1.13
				N/A	N/A	S-U3	19.1	Mercury	1.67E-04	AP42 Table 3.1-5	N/A	N/A	3.18E-03	3.18E-03	1.72E-03	1.72E-03
				N/A	N/A	S-U3	19.1	Nickel	6.39E-04	AP42 Table 3.1-5	N/A	N/A	0.012	0.012	6.58E-03	6.58E-03
				N/A	N/A	S-U3	19.1	Selenium	3.48E-03	AP42 Table 3.1-5	N/A	N/A	0.066	0.066	0.036	0.036
				N/A	N/A	S-U3	19.1	N2O	0.183	AP-42, Table 3.1-2a	N/A	N/A	3.48	3.48	1.88	1.88
				N/A	N/A	S-U3	19.1	Total HAP	0.170	Sum of HAPs	N/A	7.42%	3.24	3.00	1.75	1.62
		03	Cold Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	0.600	NOX	288	Vendor Estimate	N/A	N/A	173	173	2.16	2.16
				N/A	N/A	S-U3	0.600	CO	9,358	Vendor Estimate	N/A	N/A	5,615	5,615	70.2	70.2
				N/A	N/A	S-U3	0.600	VOC	824	Vendor Estimate	N/A	N/A	494	494	6.18	6.18
				N/A	N/A	S-U3	0.600	PM-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U3	0.600	PM10-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U3	0.600	PM2.5-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U3	0.600	SO2	3.20	Vendor Estimate	N/A	N/A	1.92	1.92	0.024	0.024
				N/A	N/A	S-U3	0.600	H2SO4	1.13	Vendor Estimate	N/A	N/A	0.677	0.677	8.46E-03	8.46E-03
				N/A	N/A	S-U3	0.600	CO2	192,828	Vendor Estimate	N/A	N/A	115,697	115,697	1,446	1,446
		04	Warm Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	0.857	NOX	159	Vendor Estimate	N/A	N/A	136	136	29.0	29.0
				N/A	N/A	S-U3	0.857	CO	4,501	Vendor Estimate	N/A	N/A	3,858	3,858	821	821
				N/A	N/A	S-U3	0.857	VOC	410	Vendor Estimate	N/A	N/A	351	351	74.8	74.8
				N/A	N/A	S-U3	0.857	PM-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U3	0.857	PM10-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U3	0.857	PM2.5-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U3	0.857	SO2	1.92	Vendor Estimate	N/A	N/A	1.65	1.65	0.351	0.351
				N/A	N/A	S-U3	0.857	H2SO4	0.677	Vendor Estimate	N/A	N/A	0.580	0.580	0.123	0.123
				N/A	N/A	S-U3	0.857	CO2	123,038	Vendor Estimate	N/A	N/A	105,461	105,461	22,454	22,454
		05	Hot Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	1.33	NOX	110	Vendor Estimate	N/A	N/A	147	147	32.2	32.2
				N/A	N/A	S-U3	1.33	CO	2,677	Vendor Estimate	N/A	N/A	3,569	3,569	783	783
				N/A	N/A	S-U3	1.33	VOC	253	Vendor Estimate	N/A	N/A	337	337	74.0	74.0
				N/A	N/A	S-U3	1.33	PM-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05
				N/A	N/A	S-U3	1.33	PM10-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05
				N/A	N/A	S-U3	1.33	PM2.5-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	S-U3	1.33	SO2	1.49	Vendor Estimate	N/A	N/A	1.99	1.99	0.437	0.437
				N/A	N/A	S-U3	1.33	H2SO4	0.526	Vendor Estimate	N/A	N/A	0.702	0.702	0.154	0.154
				N/A	N/A	S-U3	1.33	CO2	96,867	Vendor Estimate	N/A	N/A	129,156	129,156	28,334	28,334
		06	Shutdown Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	2.00	NOX	56.0	Vendor Estimate	N/A	N/A	112	112	27.0	27.0
				N/A	N/A	S-U3	2.00	CO	849	Vendor Estimate	N/A	N/A	1,698	1,698	410	410
				N/A	N/A	S-U3	2.00	VOC	64.0	Vendor Estimate	N/A	N/A	128	128	30.9	30.9
				N/A	N/A	S-U3	2.00	PM-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U3	2.00	PM10-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U3	2.00	PM2.5-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U3	2.00	SO2	0.640	Vendor Estimate	N/A	N/A	1.28	1.28	0.309	0.309
				N/A	N/A	S-U3	2.00	H2SO4	0.226	Vendor Estimate	N/A	N/A	0.451	0.451	0.109	0.109
				N/A	N/A	S-U3	2.00	CO2	66,924	Vendor Estimate	N/A	N/A	133,848	133,848	32,291	32,291
		07	Cold Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	0.545	NOX	556	Vendor Estimate	N/A	N/A	303	303	4.17	4.17
				N/A	N/A	S-U3	0.545	CO	15,416	Vendor Estimate	N/A	N/A	8,409	8,409	116	116
				N/A	N/A	S-U3	0.545	VOC	1,780	Vendor Estimate	N/A	N/A	971	971	13.4	13.4
				N/A	N/A	S-U3	0.545	PM-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U3	0.545	PM10-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U3	0.545	PM2.5-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U3	0.545	SO2	2.88	Vendor Estimate	N/A	N/A	1.57	1.57	0.022	0.022
				N/A	N/A	S-U3	0.545	H2SO4	1.01	Vendor Estimate	N/A	N/A	0.552	0.552	7.60E-03	7.60E-03
				N/A	N/A	S-U3	0.545	CO2	252,300	Vendor Estimate	N/A	N/A	137,618	137,618	1,892	1,892
		08	Warm Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	0.800	NOX	310	Vendor Estimate	N/A	N/A	248	248	2.33	2.33
				N/A	N/A	S-U3	0.800	CO	7,462	Vendor Estimate	N/A	N/A	5,970	5,970	56.0	56.0
				N/A	N/A	S-U3	0.800	VOC	872	Vendor Estimate	N/A	N/A	698	698	6.54	6.54
				N/A	N/A	S-U3	0.800	PM-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U3	0.800	PM10-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U3	0.800	PM2.5-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U3	0.800	SO2	1.70	Vendor Estimate	N/A	N/A	1.36	1.36	0.013	0.013
				N/A	N/A	S-U3	0.800	H2SO4	0.598	Vendor Estimate	N/A	N/A	0.479	0.479	4.49E-03	4.49E-03
				N/A	N/A	S-U3	0.800	CO2	162,553	Vendor Estimate	N/A	N/A	130,042	130,042	1,219	1,219
		09	Hot Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	1.33	NOX	217	Vendor Estimate	N/A	N/A	289	289	3.26	3.26
				N/A	N/A	S-U3	1.33	CO	4,477	Vendor Estimate	N/A	N/A	5,969	5,969	67.2	67.2
				N/A	N/A	S-U3	1.33	VOC	530	Vendor Estimate	N/A	N/A	707	707	7.95	7.95
				N/A	N/A	S-U3	1.33	PM-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U3	1.33	PM10-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U3	1.33	PM2.5-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U3	1.33	SO2	1.31	Vendor Estimate	N/A	N/A	1.74	1.74	0.020	0.020
				N/A	N/A	S-U3	1.33	H2SO4	0.460	Vendor Estimate	N/A	N/A	0.614	0.614	6.91E-03	6.91E-03
				N/A	N/A	S-U3	1.33	CO2	128,897	Vendor Estimate	N/A	N/A	171,863	171,863	1,933	1,933
		10	Shutdown Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U3	2.00	NOX	100	Vendor Estimate	N/A	N/A	200	200	3.00	3.00
				N/A	N/A	S-U3	2.00	CO	1,215	Vendor Estimate	N/A	N/A	2,430	2,430	36.5	36.5
				N/A	N/A	S-U3	2.00	VOC	122	Vendor Estimate	N/A	N/A	244	244	3.66	3.66
				N/A	N/A	S-U3	2.00	PM-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U3	2.00	PM10-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U3	2.00	PM2.5-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U3	2.00	SO2	0.654	Vendor Estimate	N/A	N/A	1.31	1.31	0.020	0.020
				N/A	N/A	S-U3	2.00	H2SO4	0.230	Vendor Estimate	N/A	N/A	0.460	0.460	6.91E-03	6.91E-03
				N/A	N/A	S-U3	2.00	CO2	82,687	Vendor Estimate	N/A	N/A	165,374	165,374	2,481	2,481

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST															
		01	Natural Gas Firing in CT					SCC Code: 20100201					SCC Units: Million Cubic Feet Natural Gas Burned			
				SCR	C1	S-U4	2.58	NOX	57.6	EKPC Calculated	N/A	86.67%	149	19.8	651	86.8
				SCR	C1	S-U4	2.58	CO	9.36	EKPC Calculated	N/A	50.00%	24.1	12.1	106	52.9
				CatOx	C2	S-U4	2.58	VOC	1.91	EKPC Calculated	N/A	30.00%	4.94	3.46	21.6	15.1
				N/A	N/A	S-U4	2.58	PM-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U4	2.58	PM10-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U4	2.58	PM2.5-TOT	6.67	Vendor Estimate	N/A	N/A	17.2	17.2	75.4	75.4
				N/A	N/A	S-U4	2.58	SO2	1.42	Pipeline spec conversion	N/A	N/A	3.67	3.67	16.1	16.1
				N/A	N/A	S-U4	2.58	H2SO4	2.18	Pipeline spec conversion	N/A	N/A	5.63	5.63	24.6	24.6
				N/A	N/A	S-U4	2.58	NH3	7.11	EKPC Requirement	N/A	N/A	18.3	18.3	80.4	80.4
				N/A	N/A	S-U4	2.58	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	309,584	309,584	1,355,978	1,355,978
				N/A	N/A	S-U4	2.58	CH4	24.9	AP-42, Table 3.1-2a	N/A	N/A	64.2	64.2	281	281
				N/A	N/A	S-U4	2.58	CO2e	121,674	40 CFR 98 Subpart A	N/A	N/A	313,855	313,855	1,374,685	1,374,685
				N/A	N/A	S-U4	2.58	N2O	3.62	AP-42, Table 3.1-2a	N/A	N/A	9.34	9.34	40.9	40.9
				CatOx	C2	S-U4	2.58	1,3-Butadiene	4.39E-04	AP-42 Table 3.1	N/A	30.00%	1.13E-03	7.92E-04	4.96E-03	3.47E-03
				CatOx	C2	S-U4	2.58	Acetaldehyde	0.256	AP-42 Table 3.1 & 3-4 of BID	N/A	30.00%	0.662	0.463	2.90	2.03
				CatOx	C2	S-U4	2.58	Acrolein	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	N/A	43.44%	0.017	9.52E-03	0.074	0.042
				CatOx	C2	S-U4	2.58	Benzene	0.012	AP-42 Table 3.1 & 3-4 of BID	N/A	72.83%	0.032	8.58E-03	0.138	0.038
				CatOx	C2	S-U4	2.58	Ethylbenzene	0.033	AP-42 Table 3.1	N/A	30.00%	0.084	0.059	0.369	0.258
				CatOx	C2	S-U4	2.58	Formaldehyde	0.724	EKPC Requirement	N/A	67.97%	1.87	0.598	8.18	2.62
				CatOx	C2	S-U4	2.58	Naphthalene	1.33E-03	AP-42 Table 3.1	N/A	30.00%	3.42E-03	2.39E-03	0.015	0.010
				CatOx	C2	S-U4	2.58	PAH	2.24E-03	AP-42 Table 3.1	N/A	30.00%	5.79E-03	4.05E-03	0.025	0.018
				CatOx	C2	S-U4	2.58	Propylene Oxide	0.030	AP-42 Table 3.1	N/A	30.00%	0.076	0.053	0.334	0.234
				CatOx	C2	S-U4	2.58	Toluene	0.133	AP-42 Table 3.1	N/A	30.00%	0.342	0.239	1.50	1.05
				CatOx	C2	S-U4	2.58	Xylenes	0.065	AP-42 Table 3.1	N/A	30.00%	0.168	0.118	0.738	0.516
				N/A	N/A	S-U4	2.58	Total HAP	1.26	Sum of HAPs	N/A	N/A	3.26	1.56	14.3	6.82
		02	No. 2 FO Firing in CT					SCC Code: 20100101					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
				SCR	C1	S-U4	19.1	NOX	13.5	EKPC Calculated	N/A	82.00%	257	46.3	139	25.0
				SCR	C1	S-U4	19.1	CO	1.31	EKPC Calculated	N/A	50.00%	25.0	12.5	13.5	6.76
				CatOx	C2	S-U4	19.1	VOC	0.269	EKPC Calculated	N/A	30.00%	5.12	3.58	2.77	1.94
				N/A	N/A	S-U4	19.1	PM-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U4	19.1	PM10-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U4	19.1	PM2.5-TOT	1.58	Vendor Estimate	N/A	N/A	30.1	30.1	16.3	16.3
				N/A	N/A	S-U4	19.1	SO2	0.207	ULSD spec conversion	N/A	N/A	3.94	3.94	2.13	2.13
				N/A	N/A	S-U4	19.1	H2SO4	0.316	ULSD spec conversion	N/A	N/A	6.03	6.03	3.26	3.26
				N/A	N/A	S-U4	19.1	NH3	0.998	EKPC Requirement	N/A	N/A	19.0	19.0	10.3	10.3
				N/A	N/A	S-U4	19.1	CO2	22,501	40 CFR 98, Table C-1	N/A	N/A	428,996	428,996	231,658	231,658
				N/A	N/A	S-U4	19.1	CH4	0.913	AP-42, Table 3.1-2a	N/A	N/A	17.4	17.4	9.40	9.40
				N/A	N/A	S-U4	19.1	CO2e	22,575	40 CFR 98 Subpart A	N/A	N/A	430,406	430,406	232,419	232,419
				CatOx	C2	S-U4	19.1	1,3-Butadiene	2.22E-03	AP42 Table 3.1-4	N/A	30.00%	0.042	0.030	0.023	0.016
				CatOx	C2	S-U4	19.1	Benzene	7.65E-03	AP42 Table 3.1-4	N/A	30.00%	0.146	0.102	0.079	0.055
				CatOx	C2	S-U4	19.1	Formaldehyde	0.030	EKPC Requirement	N/A	21.84%	0.568	0.444	0.307	0.240
				CatOx	C2	S-U4	19.1	Naphthalene	4.87E-03	AP42 Table 3.1-4	N/A	30.00%	0.093	0.065	0.050	0.035
				CatOx	C2	S-U4	19.1	PAH	5.56E-03	AP42 Table 3.1-4	N/A	30.00%	0.106	0.074	0.057	0.040
				N/A	N/A	S-U4	19.1	Arsenic	1.53E-03	AP42 Table 3.1-5	N/A	N/A	0.029	0.029	0.016	0.016
				N/A	N/A	S-U4	19.1	Beryllium	4.31E-05	AP42 Table 3.1-5	N/A	N/A	8.22E-04	8.22E-04	4.44E-04	4.44E-04
				N/A	N/A	S-U4	19.1	Cadmium	6.67E-04	AP42 Table 3.1-5	N/A	N/A	0.013	0.013	6.87E-03	6.87E-03
				N/A	N/A	S-U4	19.1	Chromium	1.53E-03	AP42 Table 3.1-5	N/A	N/A	0.029	0.029	0.016	0.016
				N/A	N/A	S-U4	19.1	Lead	1.95E-03	AP42 Table 3.1-5	N/A	N/A	0.037	0.037	0.020	0.020
				N/A	N/A	S-U4	19.1	Manganese	0.110	AP42 Table 3.1-5	N/A	N/A	2.09	2.09	1.13	1.13
				N/A	N/A	S-U4	19.1	Mercury	1.67E-04	AP42 Table 3.1-5	N/A	N/A	3.18E-03	3.18E-03	1.72E-03	1.72E-03
				N/A	N/A	S-U4	19.1	Nickel	6.39E-04	AP42 Table 3.1-5	N/A	N/A	0.012	0.012	6.58E-03	6.58E-03
				N/A	N/A	S-U4	19.1	Selenium	3.48E-03	AP42 Table 3.1-5	N/A	N/A	0.066	0.066	0.036	0.036

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	S-U4	19.1	N2O	0.183	AP-42, Table 3.1-2a	N/A	N/A	3.48	3.48	1.88	1.88
				N/A	N/A	S-U4	19.1	Total HAP	0.170	Sum of HAPs	N/A	7.42%	3.24	3.00	1.75	1.62
		03	Cold Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	0.600	NOX	288	Vendor Estimate	N/A	N/A	173	173	2.16	2.16
				N/A	N/A	S-U4	0.600	CO	9,358	Vendor Estimate	N/A	N/A	5,615	5,615	70.2	70.2
				N/A	N/A	S-U4	0.600	VOC	824	Vendor Estimate	N/A	N/A	494	494	6.18	6.18
				N/A	N/A	S-U4	0.600	PM-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U4	0.600	PM10-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U4	0.600	PM2.5-TOT	15.0	Vendor Estimate	N/A	N/A	9.00	9.00	0.113	0.113
				N/A	N/A	S-U4	0.600	SO2	3.20	Vendor Estimate	N/A	N/A	1.92	1.92	0.024	0.024
				N/A	N/A	S-U4	0.600	H2SO4	1.13	Vendor Estimate	N/A	N/A	0.677	0.677	8.46E-03	8.46E-03
				N/A	N/A	S-U4	0.600	CO2	192,828	Vendor Estimate	N/A	N/A	115,697	115,697	1,446	1,446
		04	Warm Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	0.857	NOX	159	Vendor Estimate	N/A	N/A	136	136	29.0	29.0
				N/A	N/A	S-U4	0.857	CO	4,501	Vendor Estimate	N/A	N/A	3,858	3,858	821	821
				N/A	N/A	S-U4	0.857	VOC	410	Vendor Estimate	N/A	N/A	351	351	74.8	74.8
				N/A	N/A	S-U4	0.857	PM-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U4	0.857	PM10-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U4	0.857	PM2.5-TOT	9.00	Vendor Estimate	N/A	N/A	7.71	7.71	1.64	1.64
				N/A	N/A	S-U4	0.857	SO2	1.92	Vendor Estimate	N/A	N/A	1.65	1.65	0.351	0.351
				N/A	N/A	S-U4	0.857	H2SO4	0.677	Vendor Estimate	N/A	N/A	0.580	0.580	0.123	0.123
				N/A	N/A	S-U4	0.857	CO2	123,038	Vendor Estimate	N/A	N/A	105,461	105,461	22,454	22,454
		05	Hot Startup Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	1.33	NOX	110	Vendor Estimate	N/A	N/A	147	147	32.2	32.2
				N/A	N/A	S-U4	1.33	CO	2,677	Vendor Estimate	N/A	N/A	3,569	3,569	783	783
				N/A	N/A	S-U4	1.33	VOC	253	Vendor Estimate	N/A	N/A	337	337	74.0	74.0
				N/A	N/A	S-U4	1.33	PM-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05
				N/A	N/A	S-U4	1.33	PM10-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05
				N/A	N/A	S-U4	1.33	PM2.5-TOT	7.00	Vendor Estimate	N/A	N/A	9.33	9.33	2.05	2.05
				N/A	N/A	S-U4	1.33	SO2	1.49	Vendor Estimate	N/A	N/A	1.99	1.99	0.437	0.437
				N/A	N/A	S-U4	1.33	H2SO4	0.526	Vendor Estimate	N/A	N/A	0.702	0.702	0.154	0.154
				N/A	N/A	S-U4	1.33	CO2	96,867	Vendor Estimate	N/A	N/A	129,156	129,156	28,334	28,334
		06	Shutdown Events on Natural Gas					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	2.00	NOX	56.0	Vendor Estimate	N/A	N/A	112	112	27.0	27.0
				N/A	N/A	S-U4	2.00	CO	849	Vendor Estimate	N/A	N/A	1,698	1,698	410	410
				N/A	N/A	S-U4	2.00	VOC	64.0	Vendor Estimate	N/A	N/A	128	128	30.9	30.9
				N/A	N/A	S-U4	2.00	PM-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U4	2.00	PM10-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U4	2.00	PM2.5-TOT	3.00	Vendor Estimate	N/A	N/A	6.00	6.00	1.45	1.45
				N/A	N/A	S-U4	2.00	SO2	0.640	Vendor Estimate	N/A	N/A	1.28	1.28	0.309	0.309
				N/A	N/A	S-U4	2.00	H2SO4	0.226	Vendor Estimate	N/A	N/A	0.451	0.451	0.109	0.109
				N/A	N/A	S-U4	2.00	CO2	66,924	Vendor Estimate	N/A	N/A	133,848	133,848	32,291	32,291
		07	Cold Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	0.545	NOX	556	Vendor Estimate	N/A	N/A	303	303	4.17	4.17
				N/A	N/A	S-U4	0.545	CO	15,416	Vendor Estimate	N/A	N/A	8,409	8,409	116	116
				N/A	N/A	S-U4	0.545	VOC	1,780	Vendor Estimate	N/A	N/A	971	971	13.4	13.4
				N/A	N/A	S-U4	0.545	PM-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U4	0.545	PM10-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U4	0.545	PM2.5-TOT	22.0	Vendor Estimate	N/A	N/A	12.0	12.0	0.165	0.165
				N/A	N/A	S-U4	0.545	SO2	2.88	Vendor Estimate	N/A	N/A	1.57	1.57	0.022	0.022
				N/A	N/A	S-U4	0.545	H2SO4	1.01	Vendor Estimate	N/A	N/A	0.552	0.552	7.60E-03	7.60E-03
				N/A	N/A	S-U4	0.545	CO2	252,300	Vendor Estimate	N/A	N/A	137,618	137,618	1,892	1,892
		08	Warm Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	0.800	NOX	310	Vendor Estimate	N/A	N/A	248	248	2.33	2.33

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	S-U4	0.800	CO	7,462	Vendor Estimate	N/A	N/A	5,970	5,970	56.0	56.0
				N/A	N/A	S-U4	0.800	VOC	872	Vendor Estimate	N/A	N/A	698	698	6.54	6.54
				N/A	N/A	S-U4	0.800	PM-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U4	0.800	PM10-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U4	0.800	PM2.5-TOT	13.0	Vendor Estimate	N/A	N/A	10.4	10.4	0.098	0.098
				N/A	N/A	S-U4	0.800	SO2	1.70	Vendor Estimate	N/A	N/A	1.36	1.36	0.013	0.013
				N/A	N/A	S-U4	0.800	H2SO4	0.598	Vendor Estimate	N/A	N/A	0.479	0.479	4.49E-03	4.49E-03
				N/A	N/A	S-U4	0.800	CO2	162,553	Vendor Estimate	N/A	N/A	130,042	130,042	1,219	1,219
		09	Hot Startup Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	1.33	NOX	217	Vendor Estimate	N/A	N/A	289	289	3.26	3.26
				N/A	N/A	S-U4	1.33	CO	4,477	Vendor Estimate	N/A	N/A	5,969	5,969	67.2	67.2
				N/A	N/A	S-U4	1.33	VOC	530	Vendor Estimate	N/A	N/A	707	707	7.95	7.95
				N/A	N/A	S-U4	1.33	PM-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U4	1.33	PM10-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U4	1.33	PM2.5-TOT	10.0	Vendor Estimate	N/A	N/A	13.3	13.3	0.150	0.150
				N/A	N/A	S-U4	1.33	SO2	1.31	Vendor Estimate	N/A	N/A	1.74	1.74	0.020	0.020
				N/A	N/A	S-U4	1.33	H2SO4	0.460	Vendor Estimate	N/A	N/A	0.614	0.614	6.91E-03	6.91E-03
				N/A	N/A	S-U4	1.33	CO2	128,897	Vendor Estimate	N/A	N/A	171,863	171,863	1,933	1,933
		10	Shutdown Events on Fuel Oil					SCC Code: 39999993					SCC Units: Each Parts Processed			
				N/A	N/A	S-U4	2.00	NOX	100	Vendor Estimate	N/A	N/A	200	200	3.00	3.00
				N/A	N/A	S-U4	2.00	CO	1,215	Vendor Estimate	N/A	N/A	2,430	2,430	36.5	36.5
				N/A	N/A	S-U4	2.00	VOC	122	Vendor Estimate	N/A	N/A	244	244	3.66	3.66
				N/A	N/A	S-U4	2.00	PM-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U4	2.00	PM10-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U4	2.00	PM2.5-TOT	5.00	Vendor Estimate	N/A	N/A	10.0	10.0	0.150	0.150
				N/A	N/A	S-U4	2.00	SO2	0.654	Vendor Estimate	N/A	N/A	1.31	1.31	0.020	0.020
				N/A	N/A	S-U4	2.00	H2SO4	0.230	Vendor Estimate	N/A	N/A	0.460	0.460	6.91E-03	6.91E-03
				N/A	N/A	S-U4	2.00	CO2	82,687	Vendor Estimate	N/A	N/A	165,374	165,374	2,481	2,481
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)															
		01	Natural Gas Firing					SCC Code: 10200602					SCC Units: Million Cubic Feet Natural Gas Burned			
				N/A	N/A	S-20	0.074	NOX	11.6	EKPC requirement (Vendor Guarantee)	N/A	N/A	0.855	0.855	3.75	3.75
				N/A	N/A	S-20	0.074	CO	3.13	EKPC requirement (Vendor Guarantee)	N/A	N/A	0.231	0.231	1.01	1.01
				N/A	N/A	S-20	0.074	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	0.406	0.406	1.78	1.78
				N/A	N/A	S-20	0.074	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.256	0.256	1.12	1.12
				N/A	N/A	S-20	0.074	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.256	0.256	1.12	1.12
				N/A	N/A	S-20	0.074	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.256	0.256	1.12	1.12
				N/A	N/A	S-20	0.074	SO2	1.43	Pipeline spec conversion	N/A	N/A	0.105	0.105	0.462	0.462
				N/A	N/A	S-20	0.074	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	8.07E-03	8.07E-03	0.035	0.035
				N/A	N/A	S-20	0.074	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	3.69E-05	3.69E-05	1.62E-04	1.62E-04
				N/A	N/A	S-20	0.074	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	8,868	8,868	38,841	38,841
				N/A	N/A	S-20	0.074	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	0.167	0.167	0.732	0.732
				N/A	N/A	S-20	0.074	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	0.017	0.017	0.073	0.073
				N/A	N/A	S-20	0.074	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	8,877	8,877	38,881	38,881
				N/A	N/A	S-20	0.074	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	1.55E-04	1.55E-04	6.80E-04	6.80E-04
				N/A	N/A	S-20	0.074	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	8.87E-05	8.87E-05	3.88E-04	3.88E-04
				N/A	N/A	S-20	0.074	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	5.54E-03	5.54E-03	0.024	0.024
				N/A	N/A	S-20	0.074	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	0.133	0.133	0.583	0.583
				N/A	N/A	S-20	0.074	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	4.51E-05	4.51E-05	1.97E-04	1.97E-04
				N/A	N/A	S-20	0.074	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	2.51E-04	2.51E-04	1.10E-03	1.10E-03
				N/A	N/A	S-20	0.074	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	1.48E-05	1.48E-05	6.47E-05	6.47E-05
				N/A	N/A	S-20	0.074	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	8.13E-05	8.13E-05	3.56E-04	3.56E-04

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				N/A	N/A	S-20	0.074	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	1.03E-04	1.03E-04	4.53E-04	4.53E-04
				N/A	N/A	S-20	0.074	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	2.81E-05	2.81E-05	1.23E-04	1.23E-04
				N/A	N/A	S-20	0.074	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	1.92E-05	1.92E-05	8.41E-05	8.41E-05
				N/A	N/A	S-20	0.074	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	1.55E-04	1.55E-04	6.80E-04	6.80E-04
				N/A	N/A	S-20	0.074	Total HAP	1.89	Sum of HAPs	N/A	N/A	0.139	0.139	0.611	0.611
EU 21	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)															
		01	Diesel Firing					SCC Code: 20100102					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
				N/A	N/A	S-21	0.113	NOX	199	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW	N/A	N/A	22.5	22.5	5.64	5.64
				N/A	N/A	S-21	0.113	CO	112	Tier 2 Emission Standards per NSPS IIII	N/A	N/A	12.7	12.7	3.16	3.16
				N/A	N/A	S-21	0.113	VOC	5.33	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW	N/A	N/A	0.603	0.603	0.151	0.151
				N/A	N/A	S-21	0.113	PM-TOT	6.40	Tier 2 Emission Standards per NSPS IIII	N/A	N/A	0.723	0.723	0.181	0.181
				N/A	N/A	S-21	0.113	PM10-TOT	6.40	Tier 2 Emission Standards per NSPS IIII	N/A	N/A	0.723	0.723	0.181	0.181
				N/A	N/A	S-21	0.113	PM2.5-TOT	6.40	Tier 2 Emission Standards per NSPS IIII	N/A	N/A	0.723	0.723	0.181	0.181
				N/A	N/A	S-21	0.113	SO2	0.208	AP-42 Table 3.4-1	N/A	N/A	0.023	0.023	5.87E-03	5.87E-03
				N/A	N/A	S-21	0.113	CO2	22,501	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2	N/A	N/A	2,544	2,544	636	636
				N/A	N/A	S-21	0.113	CH4	0.913	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2	N/A	N/A	0.103	0.103	0.026	0.026
				N/A	N/A	S-21	0.113	N2O	0.183	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2	N/A	N/A	0.021	0.021	5.16E-03	5.16E-03
				N/A	N/A	S-21	0.113	CO2e	22,575	40 CFR 98, Subpart A	N/A	N/A	2,553	2,553	638	638
				N/A	N/A	S-21	0.113	Acetaldehyde	3.45E-03	AP-42 Table 3.4-3	N/A	N/A	3.90E-04	3.90E-04	9.76E-05	9.76E-05
				N/A	N/A	S-21	0.113	Acrolein	1.08E-03	AP-42 Table 3.4-3	N/A	N/A	1.22E-04	1.22E-04	3.05E-05	3.05E-05
				N/A	N/A	S-21	0.113	Benzene	0.106	AP-42 Table 3.4-3	N/A	N/A	0.012	0.012	3.01E-03	3.01E-03
				N/A	N/A	S-21	0.113	Formaldehyde	0.011	AP-42 Table 3.4-3	N/A	N/A	1.22E-03	1.22E-03	3.06E-04	3.06E-04
				N/A	N/A	S-21	0.113	Naphthalene	0.018	AP-42 Table 3.4-4	N/A	N/A	2.01E-03	2.01E-03	5.04E-04	5.04E-04
				N/A	N/A	S-21	0.113	PAH	0.029	AP-42 Table 3.4-4	N/A	N/A	3.28E-03	3.28E-03	8.21E-04	8.21E-04
				N/A	N/A	S-21	0.113	Toluene	0.039	AP-42 Table 3.4-3	N/A	N/A	4.35E-03	4.35E-03	1.09E-03	1.09E-03
				N/A	N/A	S-21	0.113	Xylenes	0.026	AP-42 Table 3.4-3	N/A	N/A	2.99E-03	2.99E-03	7.48E-04	7.48E-04
				N/A	N/A	S-21	0.113	Total HAP	0.233	AP-42 Table 3.4-3	N/A	N/A	0.026	0.026	6.60E-03	6.60E-03
EU 22	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp															
		01	Diesel Firing					SCC Code: 20100102					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
				N/A	N/A	S-22	0.016	NOX	118	= 4 g/kW-hr * 0.925 / 1.341 hp/kW	N/A	N/A	1.89	1.89	0.471	0.471
				N/A	N/A	S-22	0.016	CO	112	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	N/A	N/A	1.78	1.78	0.444	0.444
				N/A	N/A	S-22	0.016	VOC	9.60	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW	N/A	N/A	0.153	0.153	0.038	0.038
				N/A	N/A	S-22	0.016	PM-TOT	6.43	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	N/A	N/A	0.103	0.103	0.026	0.026
				N/A	N/A	S-22	0.016	PM10-TOT	6.43	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	N/A	N/A	0.103	0.103	0.026	0.026

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
				N/A	N/A	S-22	0.016	PM2.5-TOT	6.43	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	N/A	N/A	0.103	0.103	0.026	0.026
				N/A	N/A	S-22	0.016	SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	N/A	N/A	3.31E-03	3.31E-03	8.27E-04	8.27E-04
				N/A	N/A	S-22	0.016	CO2	22,501	40 CFR 98, Subpart C, Table C-1	N/A	N/A	359	359	89.6	89.6
				N/A	N/A	S-22	0.016	CH4	0.913	40 CFR 98, Subpart C, Table C-2	N/A	N/A	0.015	0.015	3.64E-03	3.64E-03
				N/A	N/A	S-22	0.016	N2O	0.183	40 CFR 98, Subpart C, Table C-2	N/A	N/A	2.91E-03	2.91E-03	7.27E-04	7.27E-04
				N/A	N/A	S-22	0.016	CO2e	22,575	40 CFR 98, Subpart A	N/A	N/A	360	360	89.9	89.9
				N/A	N/A	S-22	0.016	1,3-Butadiene	5.36E-03	AP-42 Table 3.3-2	N/A	N/A	8.54E-05	8.54E-05	2.13E-05	2.13E-05
				N/A	N/A	S-22	0.016	Acetaldehyde	0.105	AP-42 Table 3.3-2	N/A	N/A	1.67E-03	1.67E-03	4.19E-04	4.19E-04
				N/A	N/A	S-22	0.016	Acrolein	0.013	AP-42 Table 3.3-2	N/A	N/A	2.02E-04	2.02E-04	5.05E-05	5.05E-05
				N/A	N/A	S-22	0.016	Benzene	0.128	AP-42 Table 3.3-2	N/A	N/A	2.04E-03	2.04E-03	5.09E-04	5.09E-04
				N/A	N/A	S-22	0.016	Formaldehyde	0.162	AP-42 Table 3.3-2	N/A	N/A	2.58E-03	2.58E-03	6.44E-04	6.44E-04
				N/A	N/A	S-22	0.016	Naphthalene	0.012	AP-42 Table 3.3-2	N/A	N/A	1.85E-04	1.85E-04	4.63E-05	4.63E-05
				N/A	N/A	S-22	0.016	PAH	0.023	AP-42 Table 3.3-2	N/A	N/A	3.67E-04	3.67E-04	9.17E-05	9.17E-05
				N/A	N/A	S-22	0.016	Toluene	0.056	AP-42 Table 3.3-2	N/A	N/A	8.93E-04	8.93E-04	2.23E-04	2.23E-04
				N/A	N/A	S-22	0.016	Xylenes	0.039	AP-42 Table 3.3-2	N/A	N/A	6.22E-04	6.22E-04	1.56E-04	1.56E-04
				N/A	N/A	S-22	0.016	Total HAP	0.542	AP-42 Table 3.3-2	N/A	N/A	8.64E-03	8.64E-03	2.16E-03	2.16E-03
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)															
		01	Natural Gas Firing					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			
				N/A	N/A	S-23	8.61E-03	NOX	50.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.431	0.431	1.89	1.89
				N/A	N/A	S-23	8.61E-03	CO	84.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.724	0.724	3.17	3.17
				N/A	N/A	S-23	8.61E-03	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	0.047	0.047	0.207	0.207
				N/A	N/A	S-23	8.61E-03	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-23	8.61E-03	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-23	8.61E-03	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-23	8.61E-03	SO2	1.43	Pipeline spec conversion	N/A	N/A	0.012	0.012	0.054	0.054
				N/A	N/A	S-23	8.61E-03	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	9.41E-04	9.41E-04	4.12E-03	4.12E-03
				N/A	N/A	S-23	8.61E-03	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	4.31E-06	4.31E-06	1.89E-05	1.89E-05
				N/A	N/A	S-23	8.61E-03	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	1,034	1,034	4,528	4,528
				N/A	N/A	S-23	8.61E-03	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	0.019	0.019	0.085	0.085
				N/A	N/A	S-23	8.61E-03	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	1.95E-03	1.95E-03	8.53E-03	8.53E-03
				N/A	N/A	S-23	8.61E-03	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	1,035	1,035	4,532	4,532
				N/A	N/A	S-23	8.61E-03	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	1.81E-05	1.81E-05	7.92E-05	7.92E-05
				N/A	N/A	S-23	8.61E-03	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	1.03E-05	1.03E-05	4.53E-05	4.53E-05
				N/A	N/A	S-23	8.61E-03	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	6.46E-04	6.46E-04	2.83E-03	2.83E-03
				N/A	N/A	S-23	8.61E-03	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	0.016	0.016	0.068	0.068
				N/A	N/A	S-23	8.61E-03	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	5.25E-06	5.25E-06	2.30E-05	2.30E-05
				N/A	N/A	S-23	8.61E-03	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	2.93E-05	2.93E-05	1.28E-04	1.28E-04
				N/A	N/A	S-23	8.61E-03	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	1.72E-06	1.72E-06	7.55E-06	7.55E-06
				N/A	N/A	S-23	8.61E-03	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	9.47E-06	9.47E-06	4.15E-05	4.15E-05
				N/A	N/A	S-23	8.61E-03	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	1.21E-05	1.21E-05	5.28E-05	5.28E-05
				N/A	N/A	S-23	8.61E-03	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	3.27E-06	3.27E-06	1.43E-05	1.43E-05
				N/A	N/A	S-23	8.61E-03	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	2.24E-06	2.24E-06	9.81E-06	9.81E-06
				N/A	N/A	S-23	8.61E-03	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	1.81E-05	1.81E-05	7.92E-05	7.92E-05
				N/A	N/A	S-23	8.61E-03	Total HAP	1.89	Sum of HAPs	N/A	N/A	0.016	0.016	0.071	0.071
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)															
		01	Natural Gas Firing					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions: Uncontrolled Potential (lb/hr)	Hourly Emissions: Controlled Potential (lb/hr)	Annual Emissions: Uncontrolled Potential (tons/yr)	Annual Emissions: Controlled Potential (tons/yr)
				N/A	N/A	S-24	8.61E-03	NOX	50.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.431	0.431	1.89	1.89
				N/A	N/A	S-24	8.61E-03	CO	84.0	AP-42 Table 1.4-1 for Small Boilers with LNB (7/98)	N/A	N/A	0.724	0.724	3.17	3.17
				N/A	N/A	S-24	8.61E-03	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	0.047	0.047	0.207	0.207
				N/A	N/A	S-24	8.61E-03	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-24	8.61E-03	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-24	8.61E-03	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.030	0.030	0.131	0.131
				N/A	N/A	S-24	8.61E-03	SO2	1.43	Pipeline spec conversion	N/A	N/A	0.012	0.012	0.054	0.054
				N/A	N/A	S-24	8.61E-03	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	9.41E-04	9.41E-04	4.12E-03	4.12E-03
				N/A	N/A	S-24	8.61E-03	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	4.31E-06	4.31E-06	1.89E-05	1.89E-05
				N/A	N/A	S-24	8.61E-03	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	1,034	1,034	4,528	4,528
				N/A	N/A	S-24	8.61E-03	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	0.019	0.019	0.085	0.085
				N/A	N/A	S-24	8.61E-03	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	1.95E-03	1.95E-03	8.53E-03	8.53E-03
				N/A	N/A	S-24	8.61E-03	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	1,035	1,035	4,532	4,532
				N/A	N/A	S-24	8.61E-03	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	1.81E-05	1.81E-05	7.92E-05	7.92E-05
				N/A	N/A	S-24	8.61E-03	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	1.03E-05	1.03E-05	4.53E-05	4.53E-05
				N/A	N/A	S-24	8.61E-03	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	6.46E-04	6.46E-04	2.83E-03	2.83E-03
				N/A	N/A	S-24	8.61E-03	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	0.016	0.016	0.068	0.068
				N/A	N/A	S-24	8.61E-03	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	5.25E-06	5.25E-06	2.30E-05	2.30E-05
				N/A	N/A	S-24	8.61E-03	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	2.93E-05	2.93E-05	1.28E-04	1.28E-04
				N/A	N/A	S-24	8.61E-03	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	1.72E-06	1.72E-06	7.55E-06	7.55E-06
				N/A	N/A	S-24	8.61E-03	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	9.47E-06	9.47E-06	4.15E-05	4.15E-05
				N/A	N/A	S-24	8.61E-03	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	1.21E-05	1.21E-05	5.28E-05	5.28E-05
				N/A	N/A	S-24	8.61E-03	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	3.27E-06	3.27E-06	1.43E-05	1.43E-05
				N/A	N/A	S-24	8.61E-03	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	2.24E-06	2.24E-06	9.81E-06	9.81E-06
				N/A	N/A	S-24	8.61E-03	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	1.81E-05	1.81E-05	7.92E-05	7.92E-05
				N/A	N/A	S-24	8.61E-03	Total HAP	1.89	Sum of HAPs	N/A	N/A	0.016	0.016	0.071	0.071
EU 25	One Mechanical Draft Cooling Tower, 9 Cells															
		01	Recirculating Water					SCC Code: 38500101					SCC Units: Million Gallons Cooling Water Throughput			
				Inherent drift eliminators	N/A	S-25	9.95	PM-TOT	0.104	2500 ppm TDS in recirculating water and 0.0005% drift	N/A	N/A	1.04	1.04	4.54	4.54
				Inherent drift eliminators	N/A	S-25	9.95	PM10-TOT	0.013	EPRI PM10/PM ratio	N/A	N/A	0.134	0.134	0.586	0.586
				Inherent drift eliminators	N/A	S-25	9.95	PM2.5-TOT	1.26E-04	EPRI PM2.5/PM ratio	N/A	N/A	1.25E-03	1.25E-03	5.48E-03	5.48E-03
EU 26A	1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs															
		01	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-26A	1.54	VOC	0.233	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	0.358	0.358	0.193	0.193
		02	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-26A	19.1	VOC	0.021	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	0.401	0.401	0.217	0.217
EU 26B	1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs															
		01	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-26B	1.54	VOC	0.233	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	0.358	0.358	0.193	0.193

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
		02	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-26B	19.1	VOC	0.021	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	0.401	0.401	0.217	0.217
EU 27	1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine															
		01	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-27	1.14E-04	VOC	0.285	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	3.25E-05	3.25E-05	1.43E-04	1.43E-04
		02	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-27	6.45E-03	VOC	0.013	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	8.65E-05	8.65E-05	3.79E-04	3.79E-04
EU 28	350 Gallon Diesel Storage Tank for Fire Pump Engine															
		01	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-28	4.00E-05	VOC	0.265	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	1.06E-05	1.06E-05	4.63E-05	4.63E-05
		02	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-28	9.09E-04	VOC	0.019	TankESP analysis using methodology presented in AP-42 Section 7.1	N/A	N/A	1.70E-05	1.70E-05	7.46E-05	7.46E-05
EU 29A	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)															
		01	Natural Gas Firing					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			
				N/A	N/A	S-29A	0.036	NOX	100	AP-42 Table 1.4-1	N/A	N/A	3.63	3.63	15.9	15.9
				N/A	N/A	S-29A	0.036	CO	84.0	AP-42 Table 1.4-1	N/A	N/A	3.05	3.05	13.4	13.4
				N/A	N/A	S-29A	0.036	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	0.200	0.200	0.875	0.875
				N/A	N/A	S-29A	0.036	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.126	0.126	0.552	0.552
				N/A	N/A	S-29A	0.036	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.126	0.126	0.552	0.552
				N/A	N/A	S-29A	0.036	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	0.126	0.126	0.552	0.552
				N/A	N/A	S-29A	0.036	SO2	1.43	Pipeline spec conversion	N/A	N/A	0.052	0.052	0.227	0.227
				N/A	N/A	S-29A	0.036	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	3.97E-03	3.97E-03	0.017	0.017
				N/A	N/A	S-29A	0.036	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	1.82E-05	1.82E-05	7.95E-05	7.95E-05
				N/A	N/A	S-29A	0.036	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	4,359	4,359	19,093	19,093
				N/A	N/A	S-29A	0.036	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	0.082	0.082	0.360	0.360
				N/A	N/A	S-29A	0.036	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	8.22E-03	8.22E-03	0.036	0.036
				N/A	N/A	S-29A	0.036	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	4,364	4,364	19,113	19,113
				N/A	N/A	S-29A	0.036	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	7.63E-05	7.63E-05	3.34E-04	3.34E-04
				N/A	N/A	S-29A	0.036	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	4.36E-05	4.36E-05	1.91E-04	1.91E-04
				N/A	N/A	S-29A	0.036	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	2.72E-03	2.72E-03	0.012	0.012
				N/A	N/A	S-29A	0.036	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	0.065	0.065	0.286	0.286
				N/A	N/A	S-29A	0.036	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	2.22E-05	2.22E-05	9.70E-05	9.70E-05
				N/A	N/A	S-29A	0.036	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	1.23E-04	1.23E-04	5.41E-04	5.41E-04
				N/A	N/A	S-29A	0.036	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	7.26E-06	7.26E-06	3.18E-05	3.18E-05
				N/A	N/A	S-29A	0.036	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	4.00E-05	4.00E-05	1.75E-04	1.75E-04
				N/A	N/A	S-29A	0.036	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	5.08E-05	5.08E-05	2.23E-04	2.23E-04
				N/A	N/A	S-29A	0.036	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	1.38E-05	1.38E-05	6.05E-05	6.05E-05
				N/A	N/A	S-29A	0.036	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	9.44E-06	9.44E-06	4.14E-05	4.14E-05
				N/A	N/A	S-29A	0.036	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	7.63E-05	7.63E-05	3.34E-04	3.34E-04
				N/A	N/A	S-29A	0.036	Total HAP	1.89	Sum of HAPs	N/A	N/A	0.069	0.069	0.300	0.300

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
EU 29B	14 Indirect-Fired HVAC Heaters (0.061 MMBtu/hr each)															
		01	Natural Gas Firing					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			
				N/A	N/A	S-29B	8.06E-04	NOX	100	AP-42 Table 1.4-1	N/A	N/A	0.081	0.081	0.353	0.353
				N/A	N/A	S-29B	8.06E-04	CO	84.0	AP-42 Table 1.4-1	N/A	N/A	0.068	0.068	0.296	0.296
				N/A	N/A	S-29B	8.06E-04	VOC	5.50	AP-42 Table 1.4-2	N/A	N/A	4.43E-03	4.43E-03	0.019	0.019
				N/A	N/A	S-29B	8.06E-04	PM-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	2.80E-03	2.80E-03	0.012	0.012
				N/A	N/A	S-29B	8.06E-04	PM10-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	2.80E-03	2.80E-03	0.012	0.012
				N/A	N/A	S-29B	8.06E-04	PM2.5-TOT	3.47	AP-42 Table 1.4-2	N/A	N/A	2.80E-03	2.80E-03	0.012	0.012
				N/A	N/A	S-29B	8.06E-04	SO2	1.43	Pipeline spec conversion	N/A	N/A	1.15E-03	1.15E-03	5.04E-03	5.04E-03
				N/A	N/A	S-29B	8.06E-04	H2SO4	0.109	Pipeline spec conversion	N/A	N/A	8.80E-05	8.80E-05	3.85E-04	3.85E-04
				N/A	N/A	S-29B	8.06E-04	Lead	5.00E-04	AP-42, Table 1.4-2	N/A	N/A	4.03E-07	4.03E-07	1.76E-06	1.76E-06
				N/A	N/A	S-29B	8.06E-04	CO2	120,019	40 CFR 98, Table C-1	N/A	N/A	96.7	96.7	424	424
				N/A	N/A	S-29B	8.06E-04	CH4	2.26	40 CFR 98, Table C-2	N/A	N/A	1.82E-03	1.82E-03	7.98E-03	7.98E-03
				N/A	N/A	S-29B	8.06E-04	N2O	0.226	40 CFR 98, Table C-2	N/A	N/A	1.82E-04	1.82E-04	7.98E-04	7.98E-04
				N/A	N/A	S-29B	8.06E-04	CO2e	120,142	40 CFR 98, Subpart A	N/A	N/A	96.8	96.8	424	424
				N/A	N/A	S-29B	8.06E-04	Benzene	2.10E-03	AP-42, Table 1.4-3	N/A	N/A	1.69E-06	1.69E-06	7.41E-06	7.41E-06
				N/A	N/A	S-29B	8.06E-04	Dichlorobenzene	1.20E-03	AP-42, Table 1.4-3	N/A	N/A	9.67E-07	9.67E-07	4.23E-06	4.23E-06
				N/A	N/A	S-29B	8.06E-04	Formaldehyde	0.075	AP-42, Table 1.4-3	N/A	N/A	6.04E-05	6.04E-05	2.65E-04	2.65E-04
				N/A	N/A	S-29B	8.06E-04	Hexane	1.80	AP-42, Table 1.4-3	N/A	N/A	1.45E-03	1.45E-03	6.35E-03	6.35E-03
				N/A	N/A	S-29B	8.06E-04	Naphthalene	6.10E-04	AP-42, Table 1.4-3	N/A	N/A	4.91E-07	4.91E-07	2.15E-06	2.15E-06
				N/A	N/A	S-29B	8.06E-04	Toluene	3.40E-03	AP-42, Table 1.4-3	N/A	N/A	2.74E-06	2.74E-06	1.20E-05	1.20E-05
				N/A	N/A	S-29B	8.06E-04	Arsenic	2.00E-04	AP-42, Table 1.4-4	N/A	N/A	1.61E-07	1.61E-07	7.06E-07	7.06E-07
				N/A	N/A	S-29B	8.06E-04	Cadmium	1.10E-03	AP-42, Table 1.4-4	N/A	N/A	8.86E-07	8.86E-07	3.88E-06	3.88E-06
				N/A	N/A	S-29B	8.06E-04	Chromium	1.40E-03	AP-42, Table 1.4-4	N/A	N/A	1.13E-06	1.13E-06	4.94E-06	4.94E-06
				N/A	N/A	S-29B	8.06E-04	Manganese	3.80E-04	AP-42, Table 1.4-4	N/A	N/A	3.06E-07	3.06E-07	1.34E-06	1.34E-06
				N/A	N/A	S-29B	8.06E-04	Mercury	2.60E-04	AP-42, Table 1.4-4	N/A	N/A	2.09E-07	2.09E-07	9.17E-07	9.17E-07
				N/A	N/A	S-29B	8.06E-04	Nickel	2.10E-03	AP-42, Table 1.4-4	N/A	N/A	1.69E-06	1.69E-06	7.41E-06	7.41E-06
				N/A	N/A	S-29B	8.06E-04	Total HAP	1.89	Sum of HAPs	N/A	N/A	1.52E-03	1.52E-03	6.66E-03	6.66E-03
EU 30	Three (3) Turbine Circuit Breakers with 30 lb. SF6 Circuits															
		01	SF6 Releases					SCC Code: 20180001					SCC Units: Each-Year Facility Operating			
				N/A	N/A	S-30	1.00	CO2e	1.21	0.5% Annual Leak Rate	N/A	N/A	1.21	1.21	5.29	5.29
EU 31	Twelve (12) Switchyard/Station Circuit Breakers each with 58 lb. SF6 Circuits															
		01	SF6 Releases					SCC Code: 20180001					SCC Units: Each-Year Facility Operating			
				N/A	N/A	S-31	1.00	CO2e	9.34	0.5% Annual Leak Rate	N/A	N/A	9.34	9.34	40.9	40.9
EU 32	CCGT Haul Roads															
		01	19% Aqueous Ammonia Delivery					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				N/A	N/A	N/A	0.020	PM-TOT	0.178	AP-42, Section 13.2.1	N/A	N/A	3.55E-03	3.55E-03	0.016	0.016
				N/A	N/A	N/A	0.020	PM10-TOT	0.036	AP-42, Section 13.2.1	N/A	N/A	7.10E-04	7.10E-04	3.11E-03	3.11E-03
				N/A	N/A	N/A	0.020	PM2.5-TOT	8.73E-03	AP-42, Section 13.2.1	N/A	N/A	1.74E-04	1.74E-04	7.64E-04	7.64E-04
		02	ULSFO Delivery					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				N/A	N/A	N/A	0.666	PM-TOT	0.255	AP-42, Section 13.2.1	N/A	N/A	0.170	0.170	0.744	0.744
				N/A	N/A	N/A	0.666	PM10-TOT	0.051	AP-42, Section 13.2.1	N/A	N/A	0.034	0.034	0.149	0.149
				N/A	N/A	N/A	0.666	PM2.5-TOT	0.013	AP-42, Section 13.2.1	N/A	N/A	8.34E-03	8.34E-03	0.037	0.037
		03	Water Treatment Building Chemicals Delivery					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				N/A	N/A	N/A	0.010	PM-TOT	0.191	AP-42, Section 13.2.1	N/A	N/A	2.00E-03	2.00E-03	8.77E-03	8.77E-03
				N/A	N/A	N/A	0.010	PM10-TOT	0.038	AP-42, Section 13.2.1	N/A	N/A	4.00E-04	4.00E-04	1.75E-03	1.75E-03
				N/A	N/A	N/A	0.010	PM2.5-TOT	9.38E-03	AP-42, Section 13.2.1	N/A	N/A	9.83E-05	9.83E-05	4.30E-04	4.30E-04
		04	Cooling Tower Chemicals Delivery					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				N/A	N/A	N/A	1.46E-03	PM-TOT	0.192	AP-42, Section 13.2.1	N/A	N/A	2.80E-04	2.80E-04	1.23E-03	1.23E-03

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions Uncontrolled Potential (lb/hr)	Hourly Emissions Controlled Potential (lb/hr)	Annual Emissions Uncontrolled Potential (tons/yr)	Annual Emissions Controlled Potential (tons/yr)
				N/A	N/A	N/A	1.46E-03	PM10-TOT	0.038	AP-42, Section 13.2.1	N/A	N/A	5.60E-05	5.60E-05	2.45E-04	2.45E-04
				N/A	N/A	N/A	1.46E-03	PM2.5-TOT	9.42E-03	AP-42, Section 13.2.1	N/A	N/A	1.37E-05	1.37E-05	6.02E-05	6.02E-05
EU 33	Natural Gas Piping Fugitives															
		01	Natural Gas Piping Fugitives - GV Valves				SCC Code: 30600811						SCC Units: Each-Year Valve Operating			
				N/A	N/A	N/A	670	VOC	0.957	Document EPA-453/R-95/017, November 1995	N/A	N/A	642	642	0.321	0.321
				N/A	N/A	N/A	670	CO2	0.376	Document EPA-453/R-95/017, November 1995	N/A	N/A	252	252	0.126	0.126
				N/A	N/A	N/A	670	CH4	74.0	Document EPA-453/R-95/017, November 1995	N/A	N/A	49,579	49,579	24.8	24.8
				N/A	N/A	N/A	670	CO2e	2,072	CO2 * CO2 GWP + CH4 * CH4 GWP	N/A	N/A	1,388,469	1,388,469	694	694
		02	Natural Gas Piping Fugitives - Relief Valves				SCC Code: 30600822						SCC Units: Each-Year Valve Operating			
				N/A	N/A	N/A	21.0	VOC	1.87	Document EPA-453/R-95/017, November 1995	N/A	N/A	39.3	39.3	0.020	0.020
				N/A	N/A	N/A	21.0	CO2	0.736	Document EPA-453/R-95/017, November 1995	N/A	N/A	15.4	15.4	7.72E-03	7.72E-03
				N/A	N/A	N/A	21.0	CH4	145	Document EPA-453/R-95/017, November 1995	N/A	N/A	3,039	3,039	1.52	1.52
				N/A	N/A	N/A	21.0	CO2e	4,053	CO2 * CO2 GWP + CH4 * CH4 GWP	N/A	N/A	85,104	85,104	42.6	42.6
		03	Natural Gas Piping Fugitives - Flanges				SCC Code: 30600816						SCC Units: Each-Year Flange Operating			
				N/A	N/A	N/A	1,980	VOC	0.083	Document EPA-453/R-95/017, November 1995	N/A	N/A	164	164	0.082	0.082
				N/A	N/A	N/A	1,980	CO2	0.033	Document EPA-453/R-95/017, November 1995	N/A	N/A	64.6	64.6	0.032	0.032
				N/A	N/A	N/A	1,980	CH4	6.41	Document EPA-453/R-95/017, November 1995	N/A	N/A	12,698	12,698	6.35	6.35
				N/A	N/A	N/A	1,980	CO2e	180	CO2 * CO2 GWP + CH4 * CH4 GWP	N/A	N/A	355,614	355,614	178	178
		04	Natural Gas Piping Fugitives - Sampling Connections				SCC Code: 20180001						SCC Units: Each-Year Facility Operating			
				N/A	N/A	N/A	2.00	VOC	1.87	Document EPA-453/R-95/017, November 1995	N/A	N/A	3.74	3.74	1.87E-03	1.87E-03
				N/A	N/A	N/A	2.00	CO2	0.736	Document EPA-453/R-95/017, November 1995	N/A	N/A	1.47	1.47	7.36E-04	7.36E-04
				N/A	N/A	N/A	2.00	CH4	145	Document EPA-453/R-95/017, November 1995	N/A	N/A	289	289	0.145	0.145
				N/A	N/A	N/A	2.00	CO2e	4,053	CO2 * CO2 GWP + CH4 * CH4 GWP	N/A	N/A	8,105	8,105	4.05	4.05
EU 34	93% Sulfuric Acid Tank															
		01	Breathing Losses				SCC Code: 42500301						SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	IA-30	3.42E-04	VOC	6.77E-05	TankESP analysis using methodology presented in AP-42 Section 7.1 and sulfuric acid partial pressure data from Perry's Chemical Engineer's Handbook, 8th Edition	N/A	N/A	2.32E-08	2.32E-08	1.02E-07	1.02E-07
		02	Working Losses				SCC Code: 42500302						SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	IA-30	2.28E-03	VOC	4.46E-06	||	N/A	N/A	1.02E-08	1.02E-08	4.46E-08	4.46E-08

Section N.2: Stack Information

UTM Zone: 16

Stack ID	Identify all Emission Units (with Process ID) and Control Devices that Feed to Stack	Stack Physical Data: Equivalent Diameter (ft)	Stack Physical Data: Height (ft)	Stack Physical Data: Base Elevation (ft)	Stack UTM Coordinates: Northing (m)	Stack UTM Coordinates: Easting (m)	Stack Gas Stream Data: Flowrate (acfm)	Stack Gas Stream Data: Temperature (°F)	Stack Gas Stream Data: Exit Velocity (ft/sec)
Combined Stack for U1 and U2	EU 2n, Indirect Heat Exchanger #2, Control Devices: LNBs, DFGD, SCR, PJFF, FuelSolv Treatment EU 1, Indirect Heat Exchanger #2, Control Devices: ESP, LNB, DFGD, PJFF	18.01	260.01	803.60	4097343	714250	958,426	160	62.7
S-U3	EU 18, Unit 3 Gas Turbine, Control Devices: U3 CatOx & U3 SCR	20.75	274.90	827.50	4097186	714592	1,148,623	177	56.6
S-U4	EU 19, Unit 4 Gas Turbine, Control Devices: U4 CatOx & U4 SCR	20.75	274.90	827.50	4097157	714631	1,148,623	177	56.6
S-17	EU 17, NG-Fired Dew Point Heater No. 1, Control Devices: N/A	3.50	36.00	804.17	4097356	714236	7,256	300	12.6
S-20	EU 20, NG-Fired Auxiliary Boiler, Control Devices: N/A	3.00	130.00	827.50	4097152	714700	27,000	300	63.7
S-21	EU 21, 1.25 MW Generator/Engine, Control Devices: N/A	1.00	13.00	827.50	4097146	714724	10,984	840	233.1
S-22	EU 22, 310 HP Diesel Pump/Engine, Control Devices: N/A	0.50	13.00	827.50	4097304	714580	1,627	986	138.1
S-23	EU 23, NG-Fired Dew Point Heater No. 2, Control Devices: N/A	2.50	16.00	827.50	4097325	714610	3,299	300	11.2
S-24	EU 24, NG-Fired Dew Point Heater No. 3, Control Devices: N/A	2.50	16.00	827.50	4097320	714607	3,299	300	11.2
S-26A	EU 26A, 1.66 MMgal Fuel Oil Storage Tank #1 for CCGTs, Control Devices: N/A	TBD	TBD	827.50	4097190	714780	TBD	Ambient	TBD
S-26B	EU 26B, 1.66 MMgal Fuel Oil Storage Tank #2 for CCGTs, Control Devices: N/A	TBD	TBD	827.50	4097190	714780	TBD	Ambient	TBD
S-25	EU 25, CCGT Cooling Tower, Control Devices: Inherent drift eliminators	33.25	38.50	827.50	4097056	714754	1,400,000	Amb.+10	26.9

Section N.3: Fugitive Information

UTM Zone: 16

Emission Unit #	Emission Unit Name	Process ID	Area Physical Data: Length of the X Side (ft)	Area Physical Data: Length of the Y Side (ft)	Area UTM Coordinates: Northing (m)	Area UTM Coordinates: Easting (m)	Area Release Data: Release Temperature (°F)	Area Release Data: Release Height (ft)
EU 27	1,000 Gallon Diesel Storage Tank for Emergency Generator's Engine	01, 02	~15	~8	4,097,146	714,724	Ambient	13.00
EU 28	350 Gallon Diesel Storage Tank for Fire Pump Engine	01, 02	~15	~8	4,097,304	714,580	Ambient	13.00
EU29A/B	Indirect-Fired HVAC Heaters (Steam Turbine Building)	01	154	154	4,097,237	714,715	Ambient	110.00
EU29A/B	Indirect-Fired HVAC Heaters (Administration)	01	122	122	4,097,175	714,689	Ambient	30.00
EU29A/B	Indirect-Fired HVAC Heaters (Water Treatment Building)	01	117	117	4,097,289	714,582	Ambient	25.00
EU29A/B	Indirect-Fired HVAC Heaters (Maintenance Shop)	01	75	75	4,097,143	714,710	Ambient	40.00
EU 30	Three (3) Turbine Circuit Breakers with 30 lb. SF6 Circuits	01	~90	~75	4,097,136	714,687	Ambient	30.00
EU 31	Twelve (12) Switchyard/Station Circuit Breakers each with 58 lb. SF6 Circuits	01	~265	~230	4,097,343	714,795	Ambient	TBD
EU 32	CCGT Haul Roads	01, 02, 03, 04	~3,000	~1,200	4,097,379	714,472	Ambient	11.47
EU 33	Natural Gas Piping Fugitives	01, 02, 03, 04	TBD	TBD	TBD	TBD	TBD	TBD
EU 34	93% Sulfuric Acid Tank	01, 02	117	117	4,097,289	714,582	Ambient	25.00

Section N.4: Notes, Comments, and Explanations

All line items on this DEP7007N form highlighted in light green correspond to revised maximum capacities, emission factors, etc. for existing emission units.
Note for EU18 and EU19: The sum of controlled potential emissions on the N.1 form for each pollutant may differ from what is presented elsewhere in this application as the PTE from these units. The PTE of each pollutant for EU18 and EU19 has been developed based on the pollutant-specific worst-case scenario inclusive of both steady-state operation and SU/SD events. However, for the purposes of actual emissions tracking and reporting on the annual KyEIS, EKPC will not be limited to the same maximum steady-state operating time while firing NG as is presented in the PTE calculations as it is feasible that the units could operate 8,760 hr/yr on just NG. 100% NG steady-state operations do not represent the worst-case emissions profile for multiple pollutants; as such, there are discrepancies between the PTE and this N form.

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
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DEP7007V

Applicable Requirements and Compliance Activities

___ Section V.1: Emission and Operating Limitation(s)
___ Section V.2: Monitoring Requirements
___ Section V.3: Recordkeeping Requirements
___ Section V.4: Reporting Requirements
___ Section V.5: Testing Requirements
___ Section V.6: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI

Source Name: East Kentucky Power Cooperative, Inc.
KY EIS (AFS): 21- 161-00009
Permit #: V-18-027
Agency Interest (AI) ID: 3808
Date: 1/24/2025

Section V.1: Emission and Operating Limitation(s)

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas						
		40 CFR 60 Subpart UUUUb	Emissions and operating limitations pursuant to 40 CFR 60 Subpart UUUUb to be provided in correlation with submittal by KDAQ of the final federally enforceable State plan by May 11, 2026.				
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)						
		Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		Boiler MACT: 40 CFR 63.7500(a)(1)	na	na	na	The permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the process heater, for each process heater.	Meet applicable work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
		Boiler MACT: 40 CFR 63.7505(a)	na	na	na	The permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the work practice standards.
		Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(3)	na	na	na	The permittee shall conduct an annual performance tune-up according to 63.7540(a)(10). Each annual tune-up specified in 63.7540(a)(10) must be no more than 13 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct annual tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
		Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.
		401 KAR 59:015. Section 4(1)(b)	PM	0.1 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
		401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
		401 KAR 59:015, Section 5(1)(b)	SO2	0.8 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST						
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST						
		40 CFR 60.4333(a); 40 CFR 63.6105(c)	na	na	na	Operate and maintain the emissions unit, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	Operate the affected source in a manner consistent with safety and good air pollution control practices.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		40 CFR 60.4320(a), 40 CFR 60 Subpart KKKK Table 1	NO_X	If the permittee operates at greater than or equal to 75 percent peak load, as a new turbine firing natural gas that has a heat input at peak load greater than 850 MMBtu/hr (HHV), peak load: 15 ppm at 15% O2, or 0.43 lb/MWh gross energy output, based upon a 30-unit operating day rolling average If the permittee operates at less than 75% of peak load (HHV), as the output is greater than 30 MW: 96 ppm at 15% O2, or 4.7 lb/MWh gross energy output, based upon a 30-unit operating day rolling average	na	na	NOX continuous emission monitoring.
		40 CFR 60.4320(a), 40 CFR 60 Subpart KKKK Table 1	NO_X	If the permittee fires fuels other than natural gas: 42 ppm at 15% O_2, or 1.3 lb/MWh gross energy output, based upon a 30-unit operating day rolling average	na	na	NOX continuous emission monitoring.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		40 CFR 60.4325, 40 CFR 60 Subpart KKKK Table 1	NO_X	If the total heat input is greater than or equal to 50% natural gas, meet the corresponding limit in Table 1 to 40 CFR 60 Subpart KKKK for natural gas-fired turbines. If the total heat input is greater than or equal to 50% distillate oil, meet the corresponding limit in Table 1 to 40 CFR 60 Subpart KKKK for distillate oil-fired turbines.	na	na	NOX continuous emission monitoring.
		40 CFR 60.4330(a)(1); 40 CFR 60.4330(a)(2)	SO_2	na	na	The permittee must not discharge into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or The permittee shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input.	Monitor fuel quality characteristics in purchase contract or tariff sheet
		40 CFR 63.6095(a)(4)	Formaldehyde	na	na	EU18 and EU19 must comply with the emissions limitations and operating limitations in this subpart upon startup .	

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		40 CFR 63.6100	Formaldehyde	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in 40 CFR 63.6175.	na	na	Continuously monitoring the inlet temperature to the catalyst and maintain the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer, when using an oxidation catalyst to comply with the formaldehyde emissions limit.
		40 CFR 60 Subpart TTTTa	40 CFR 60 Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit conditions are not provided.				
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)						
		40 CFR 60.48c(g)(2)	SO2	na	na	As an alternative to meeting the requirements of paragraph (g)(1), the permittee of an affected facility that combusts only natural gas using fuel certification in §60.48c(f) to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.	Equipment design and use of natural gas as fuel.
		Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(1)	na	na	na	The permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the boiler, for each boiler.	Meet applicable work practice standards.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
		Boiler MACT: 40 CFR 63.7505(a)	na	na	na	The permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the work practice standards.
		Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(3)	na	na	na	The permittee shall conduct an annual performance or 5-year tune-up according to 63.7540(a)(10). Each annual tune-up specified in 63.7540(a)(10) must be no more than 13 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct annual tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
		Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		Boiler MACT: 40 CFR 63.7540(a)(12)	na	na	na	If the boiler has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the permittee must conduct a tune-up of the boiler every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The permittee may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the permittee must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the permittee shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.	Conduct annual tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
		401 KAR 59:015. Section 4(1)(b)	PM	0.10 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
		401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
		401 KAR 59:015, Section 5(1)(b)	SO2	0.8 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
		401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.
EU 21	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)						
		NSPS IIII: 40 CFR 60.4205(b); 60.4206	NMHC + NOx	From 60.4202 referenced in 60.4205, NMHC + NOx shall not exceed 6.4 g/kW-hr according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		NSPS IIII: 40 CFR 60.4205(b); 60.4206	CO	From 60.4202 referenced in 60.4205, CO shall not exceed 3.5 g/kW-hr according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4205(b); 60.4206	PM	From 60.4202 referenced in 60.4205, PM shall not exceed 0.20 g/kW-hr according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4205(b); 60.4206	Opacity	From 60.4202 referenced in 60.4205, exhaust opacity shall not exceed 20 percent during acceleration mode; 15 percent during lugging mode; and 50 percent during the peaks in either mode as described in 40 CFR 1039.105.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4207(b)	na	na	na	Must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel.	Use only nonroad diesel fuel via 40 CFR 1039.305
		NSPS IIII: 40 CFR 60.4211(a)	na	na	na	Operate and maintain stationary CI internal combustion engine and control device according to manufacturer's instructions.	Only operate following manufacturer's instructions.
		NSPS IIII: 40 CFR 60.4211(f)	na	na	na	Operate according to the requirements in (f)(1) - (3) to be considered an emergency stationary ICE.	Monitor hours of operation in emergency and non-emergency service and the reason the engine was in operation during that time.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
EU 22	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp						
		NESHAP ZZZZ: 40 CFR 63.6590(c)	na	na	na	Meet the requirements of NESHAP ZZZZ by complying with NSPS IIII.	Comply with NSPS IIII.
		NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	NMHC + NOx	4.0 g/kW-hr (3.0 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	CO	3.5 g/kW-hr (2.6 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	PM	0.20 g/kW-hr (0.15 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).
		NSPS IIII: 40 CFR 60.4207(b)	na	na	na	Use diesel fuel that meets requirements of 40 CFR 1090.305 for nonroad diesel fuel.	Purchase only compliant diesel fuel.
		NSPS IIII: 40 CFR 60.4211(a)	na	na	na	Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions. Change only those emission-related settings that are permitted by the manufacturer. Meet the requirements of 40 CFR part 1068, as they apply.	Maintain records of maintenance conducted on the engine consistent with the operating requirements of 40 CFR 60.4206 and 40 CFR 60.4211(a).

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		NSPS IIII: 40 CFR 60.4211(f)	na	na	na	Operate according to the requirements in (f)(1) - (3) to be considered an emergency stationary ICE.	Monitor hours of operation in emergency and non-emergency service and the reason the engine was in operation during that time.
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)						
		Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The Permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(1)	na	na	na	The Permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the process heater, for each process heater.	Meet applicable work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
		Boiler MACT: 40 CFR 63.7505(a)	na	na	na	The Permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the work practice standards.
		Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(2)	na	na	na	The Permittee shall conduct a biennial performance tune-up according to 63.7540(a)(11). Each biennial tune-up specified in 63.7540(a)(11) must be no more than 25 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct biennial tune-up. Or tune-up every 5 years if using continuous oxygen trim system.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The Permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.
		401 KAR 59:015.	PM	0.1 lb/MMBtu	na	na	Equipment design and use
		401 KAR 59:015,	Opacity	20%	na	na	Equipment design and use
		401 KAR 59:015,	SO2	0.8 lb/MMBtu	na	na	Equipment design and use
		401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)						
		Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(1)	na	na	na	The permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the process heater, for each process heater.	Meet applicable work practice standards.
		Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
		Boiler MACT: 40 CFR 63.7505(a)	na	na	na	The permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the work practice standards.
		Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(2)	na	na	na	The Permittee shall conduct a biennial performance tune-up according to 63.7540(a)(11). Each biennial tune-up specified in 63.7540(a)(11) must be no more than 25 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct biennial tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
		Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		401 KAR 59:015.	PM	0.1 lb/MMBtu	na	na	Equipment design and use
		401 KAR 59:015,	Opacity	20%	na	na	Equipment design and use
		401 KAR 59:015,	SO2	0.8 lb/MMBtu	na	na	Equipment design and use
		401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.
EU 25	One Mechanical Draft Cooling Tower, 9 Cells						
		401 KAR 59:010, Section 3(1)(a)	Opacity	The permittee shall not cause, suffer, allow or permit any continuous emission into the open air from a control device or stack associated with any affected facility which is equal to or greater than twenty (20) percent opacity.	na	na	Equipment design (drift eliminators) and proper operation.
		401 KAR 59:010, Section 3(2)	PM	PM emissions shall not be more than the lbs/hr limit calculated by the equation in 59:010.	na	na	Equipment design (drift eliminators) and proper operation.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
EU 29A	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)						
		401 KAR 59:015, Section 7	na	na	na	During a startup period or shutdown period, comply with the work practice standards established in 401 KAR 59:015, Section 7: (1) i. Comply with 401 KAR 50:055, Section 2(5); ii. The frequency and duration of startup periods or shutdown periods shall be minimized by the affected facility; iii. All reasonable steps shall be taken by the permittee to minimize the impact of emissions on ambient air quality from the affected facility during startup periods and shutdown periods; iv. Startups and shutdowns shall be conducted according to either: 1. The manufacturer's recommended procedures; 2. Recommended procedures for a unit of similar design, for which manufacturer's recommended procedures are available, as approved by the cabinet based on documentation provided by the permittee.	Maintain logs or other relevant evidence.
		401 KAR 59:015, Section 4(1)(b)	PM	Except as established in 401 KAR 59:015, Sections 3(3) and 7, the permittee shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu	na	na	Compliance is assumed while burning natural gas.
		401 KAR 59:015, Section 4(2)	Opacity	Except as established in 401 KAR 59:015, Sections 3(3) and 7, the permittee shall not cause emissions in excess of 20% opacity.	na	na	Compliance is assumed while burning natural gas.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		401 KAR 59:015, Section 5(1)(b)1	SO2	Except as established in 401 KAR 59:015, Sections 3(3) and 7, the permittee shall not cause emissions of gases that contain sulfur dioxide in excess of 0.8 lb/MMBtu	na	na	Compliance is assumed while burning natural gas.
EU 32	CCGT Haul Roads						
		401 KAR 63:010, Section 3(1)	PM	na	na	The permittee shall not cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished; or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Reasonable precautions shall include, as applicable: i. Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts; ii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or other similar operations. iii. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; iv. The maintenance of paved roadways in a clean condition; or v. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water.	Monitoring and recordkeeping requirements

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
		401 KAR 63:010, Section 3(2)	PM	**Fugitive Emission Standard:** For each affected facility that is not subject to the opacity standards in 401 KAR 59:010, and that emits or may emit any air contaminant into the air outside buildings, structures, and equipment other than from a stack or air pollution control equipment exhaust: i. The permittee shall not cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate, as determined by Reference Method 22 of Appendix A in 40 C.F.R. Part 60, for: 1) More than five (5) minutes of emission time during any sixty (60) minute observation period; or 2) More than twenty (20) minutes of emission time during any twenty-four (24) hour period	na	na	Monitoring and recordkeeping requirements

Section V.2: Monitoring Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas				
			40 CFR 60 Subpart UUUUb	Monitoring requirements pursuant to 40 CFR 60 Subpart UUUUb to be provided in correlation with submittal by KDAQ of the final federally enforceable State plan by May 11, 2026.	
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)				
		na	40 CFR 60.48c(g)(2)	NG Usage	The permittee shall monitor natural gas (MMscf) on a monthly basis.
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST				
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST				
		NO_X	40 CFR 60.4335(b)(1)-(3)	NO_X emissions	Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) in accordance with 40 CFR 60.4345 consisting of a NOX monitor and a diluent gas (oxygen (O2) or carbon dioxide (CO2)) monitor, to determine the hourly NOX emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu). For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours.
		NO_X	40 CFR 60.4350	NO_X emissions	Identify excess emissions using the guidelines for CEMS equipment specified in 40 CFR 60.4350(a)-(f) and (h).
		SO_2	40 CFR 60.4365(a)	Fuel sulfur content	The permittee must demonstrate that the fuel used will not exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. The permittee must demonstrate that the fuel will have a total sulfur content in NG of 20 grains of sulfur or less per 100 standard cubic feet and will have a total sulfur content in FO of 0.05% by weight or less by using fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
		Formaldehyde	40 CFR 63.6125(a)	Catalyst inlet temperature	For each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst, maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
		Formaldehyde	40 CFR 63.6125(d)	FO usage	If the permittee operates a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and uses any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, monitor and record the distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.
		Formaldehyde	40 CFR 63.6135(a)	Catalyst inlet temperature	Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating.
		Formaldehyde	40 CFR 63.6135(b)	Catalyst inlet temperature	Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.
			40 CFR 60 Subpart TTTTa	40 CFR 60 Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit conditions are not provided.	
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)				
		na	40 CFR 60.48c(g)(2)	NG Usage	The permittee shall monitor natural gas (MMscf or MMBtu) on a monthly basis.
EU 21	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)				
		na	NSPS IIII: 40 CFR 60.4209(a)	Operating Hours	Install a non-resettable hour meter prior to startup of the engine and monitor hours of operation.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
EU 22	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp				
		na	NSPS IIII: 40 CFR 60.4209(a)	Operating Hours	Install a non-resettable hour meter prior to startup of the engine and monitor hours of operation.
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	401 KAR 52:020, Section 10	NG Usage	Monitor natural gas usage (MMscf) on a monthly basis.
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	401 KAR 52:020, Section 10	NG Usage	Monitor natural gas usage (MMscf) on a monthly basis.
EU 25	One Mechanical Draft Cooling Tower, 9 Cells				
		VE	401 KAR 52:020, Section 10	Processing Rate	The permittee shall monitor the processing rate (gallons/hr, gallons/month) and total dissolved solids content on a monthly basis.
		PM	401 KAR 52:020, Section 10	Processing Rate	The permittee shall monitor the processing rate (gallons/hr, gallons/month) and total dissolved solids content on a monthly basis.
EU 29A	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)				
		na	401 KAR 52:020, Section 10	NG Usage	Monitor natural gas usage (MMscf) on a monthly basis.
EU 32	CCGT Haul Roads				
		PM	401 KAR 63:010, Section 3(1)	na	Monitor the reasonable precautions taken to prevent particulate matter from becoming airborne on a daily basis.
		PM	401 KAR 63:010, Section 3(2)	na	If fugitive dust emissions beyond the lot line of the property are observed, conduct Reference Method 22 (visual determination of fugitive emissions) observations per Appendix A of 40 CFR Part 60. In lieu of conducted US EPA Reference Method 22, immediately perform a corrective action which results in no visible fugitive dust emissions beyond the lot line of the property.

Section V.3: Recordkeeping Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas				
			40 CFR 60 Subpart UUUUb	Recordkeeping requirements pursuant to 40 CFR 60 Subpart UUUUb to be provided in correlation with submittal by KDAQ of the final federally enforceable State plan by May 11, 2026.	
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)				
		na	NSPS Dc: 40 CFR 60.48c(g)	Fuel Combusted	Maintain records of fuel combusted during each calendar month by 60.48c(g)(2) and maintain the records for two years following the date of the record by 60.48c(i).
		na	Boiler MACT: 40 CFR 63.7555(a)	na	The permittee shall keep records according to 63.7555(a)(1) and (2).
		na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
		na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
		na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
		na	Boiler MACT: 40 CFR 63.7560(c)	na	The permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
		na	NSPS Dc: 40 CFR 60.48c(i)	na	All records required under 40 CFR 60.48c shall be maintained by the permittee of the affected facility for a period of two years following the date of such record.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST				
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST				
		NO_X	40 CFR 60.4350(b)	NO_X Emission Rate	For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NOX and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOX emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR 60. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.
		na	40 CFR 63.6155(a)	Notifications and Reports	Keep the records as described in 40 CFR 63.6155(a)(1) through (7).
		na	40 CFR 63.6155(b)	FO usage	Keep the records of the daily fuel usage.
		na	40 CFR 63.6155(c)	Catalyst inlet temperature	Keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies.
		na	40 CFR 63.6155(d)	na	Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the Division or the EPA as part of an on-site compliance evaluation.
		na	40 CFR 63.6125(e)	Catalyst inlet temperature	Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that included written procedures for CMS according to 40 CFR 63.8(d)(1) through (2). The permittee must keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Division. If the performance evaluation plan is revised, the permittee shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Division, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under 40 CFR 63.8(d)(2).
			40 CFR 60 Subpart TTTTa	40 CFR 60 Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit conditions are not provided.	

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)				
		na	NSPS Dc: 40 CFR 60.48c(g)	Fuel Combusted	Maintain records of fuel combusted during each calendar month by 60.48c(g)(2) and maintain the records for two years following the date of the record by 60.48c(i).
		na	Boiler MACT: 40 CFR 63.7555(a)	na	The permittee shall keep records according to 63.7555(a)(1) and (2).
		na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
		na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
		na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
		na	Boiler MACT: 40 CFR 63.7560(c)	na	The permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
		na	NSPS Dc: 40 CFR 60.48c(i)	na	All records required under 40 CFR 60.48c shall be maintained by the permittee of the affected facility for a period of two years following the date of such record.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EU 21	Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)				
		na	NSPS IIII: 40 CFR 60.4214(b)	Operating Hours	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The permittee must record the time of operation of the engine and the reason the engine was in operation during that time.
EU 22	Diesel-Fired Fire Pump Engine, Manufacturer/Make/Model TBD, NSPS IIII compliant, 310 bhp				
		na	NSPS IIII: 40 CFR 60.4214(b)	Operating Hours	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The permittee must record the time of operation of the engine and the reason the engine was in operation during that time.
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	401 KAR 52:020, Section 10	NG Usage	Record natural gas (MMscf) on a monthly basis.
		na	Boiler MACT: 40 CFR 63.7555(a)	na	The permittee shall keep records according to 63.7555(a)(1) and (2).
		na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
		na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
		na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
		na	Boiler MACT: 40 CFR 63.7560(c)	na	The permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	401 KAR 52:020, Section 10	NG Usage	Record natural gas (MMscf) on a monthly basis.
		na	Boiler MACT: 40 CFR 63.7555(a)	na	The permittee shall keep records according to 63.7555(a)(1) and (2).
		na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
		na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
		na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
		na	Boiler MACT: 40 CFR 63.7560(c)	na	The permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
EU 25	One Mechanical Draft Cooling Tower, 9 Cells				
		VE	401 KAR 52:020, Section 10	Processing Rate	Retain records of the processing rate (gallons/hr, gallons/month) and total dissolved solids content on a monthly basis.
		PM	401 KAR 52:020, Section 10	Processing Rate	Retain records of the processing rate (gallons/hr, gallons/month) and total dissolved solids content on a monthly basis.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EU 29A	7 Indirect-Fired HVAC Heaters (5.5 MMBtu/hr each)				
		na	401 KAR 59:015, Section 7	na	Document via a signed, contemporaneous log or other relevant evidence the actions, including duration of the startup period, of the permittee during startup periods and shutdown periods.
		na	401 KAR 52:020, Section 10	NG Usage	Record natural gas (MMscf) on a monthly basis.
EU 32	CCGT Haul Roads				
		PM	401 KAR 63:010, Section 3(1)	na	Maintain a log of the reasonable precautions taken to prevent particulate matter from becoming airborne on a daily basis. Notation of the operating status, down-time, or relevant weather conditions are acceptable for entry to the log.
		PM	401 KAR 63:010, Section 3(2)	na	Maintain a log of any Reference Method 22 performed and field records identified in Reference Method 22 and any corrective action taken and the results.

Section V.4: Reporting Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas				
			40 CFR 60 Subpart UUUUb	Reporting requirements pursuant to 40 CFR 60 Subpart UUUUb to be provided in correlation with submittal by KDAQ of the final federally enforceable State plan by May 11, 2026.	
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)				
		na	NSPS Dc: 40 CFR 60.48c(a)	Initial Notifications	Submit notification of date of construction or reconstruction and actual startup as provided by 60.7. Notification shall include design heat input capacity and identification of fuels to be combusted, annual capacity factor anticipates operating based on each fuel fired and all fuels fired.
		na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
		na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The Permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
		na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
		na	Boiler MACT: 40 CFR 63.7545(a)	na	The Permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
		na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
		na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
		na	Boiler MACT: 40 CFR 63.7550(a)	na	The Permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
		na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the Permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.
		na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
		na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
		na	Boiler MACT: 40 CFR 63.7550(h)	na	The Permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST				
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST				
		NO_X	40 CFR 60.4375(a); 40 CFR 60.4375(b)	NO_X excess emissions	Submit reports of excess emissions and monitor downtime, as defined in 40 CFR 60.4380(b), in accordance with 40 CFR 60.7. Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. For each affected unit that performs annual performance tests in accordance with §60.4340(a), the permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.
		NO_X	40 CFR 60.4395	NO_X excess emissions	Submit reports of excess emissions to the Division semiannually, except when more frequent reporting is specifically required by an applicable subpart; or the Division, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance of the source. All reports shall be postmarked by the 30th day following the end of each six month period.
		Formaldehyde	40 CFR 63.6140(b)	Emission/Operating Limits	Report each instance in which each emission limitation or operating limitation was not met. Report each instance in which the requirements in Table 7 40 CFR 63 Subpart YYYY that apply were not met. These instances are deviations from the emission and operating limitations 40 CFR 63 Subpart YYYY. These deviations must be reported according to the requirements in 40 CFR 63.6150.
		na	40 CFR 63.6145(a)	na	Submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8(f)(4), and 63.9(b) and (h) that apply by the dates specified.
		na	40 CFR 63.6145(e)	Initial Performance Test	If required to conduct an initial performance test, submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1).
		na	40 CFR 63.6145(f)	Notification of Compliance	Submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		Formaldehyde	40 CFR 63.6150(a)	Semiannual Compliance Report	Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of 40 CFR 63 Subpart YYYY. The semiannual compliance report must contain the information described in 40 CFR 63.6150 (a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of 40 CFR 63.10(e)(3), must be submitted by the dates specified in paragraphs (b)(1) through (5) of this section, unless the Division has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g).
		Formaldehyde	40 CFR 63.6150(b)	Semiannual Compliance Report	The first semiannual report and each subsequent semiannual report shall cover the periods specified in 40 CFR 63.6150(b)(1) and (3), respectively. The first semiannual report and each subsequent semiannual report shall be postmarked or delivered no later than the dates specified in 40 CFR 63.6150(b)(2) and (4), respectively.
		Formaldehyde	40 CFR 63.6150(b)(5)	Semiannual Compliance Report	For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in 40 CFR 63.6150(b)(1) through (4).
		Formaldehyde	40 CFR 63.6150(e)	Annual Compliance Report	If the permittee is operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and uses any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, submit an annual report according to Table 6 of 40 CFR 63 Subpart YYYY by the date specified unless the Administrator has approved a different schedule, according to the information described in 40 CFR 63.6150(d)(1) through (5). Report the data specified in 40 CFR 63.6150(e)(1) through (3). Submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g).
		Formaldehyde	40 CFR 63.6150(f)	Performance Test Report	Within 60 days after the date of completing each performance test required by 40 CFR 63 Subpart YYYY, submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		na	40 CFR 60.7(a)(1); 40 CFR 60.7(a)(3)	Notification of Compliance	(a)A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. [40 CFR 60.7(a)(1)] (b)A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date. [40 CFR 60.7(a)(3)]
			40 CFR 60 Subpart TTTTa	40 CFR 60 Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit conditions are not provided.	
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)				
		na	NSPS Dc: 40 CFR 60.48c(a)	Initial Notifications	Submit notification of date of construction or reconstruction and actual startup as provided by 60.7. Notification shall include design heat input capacity and identification of fuels to be combusted, annual capacity factor anticipates operating based on each fuel fired and all fuels fired.
		na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
		na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
		na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
		na	Boiler MACT: 40 CFR 63.7545(a)	na	The permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
		na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
		na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
		na	Boiler MACT: 40 CFR 63.7550(a)	na	The permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
		na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.
		na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
		na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
		na	Boiler MACT: 40 CFR 63.7550(h)	na	The permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).
EU 21	**Emergency Generator w/ Diesel-Fired Engine, Manufacturer/Make/Model TBD, Tier 2 compliant, 1.25 MW (2,200 bhp)**				
		na	RICE MACT: 40 CFR 63.6645(f)	Initial Notifications	Submit initial notification in accordance with 40 CFR 63.9(b)(2)(i) through (v) and a statement that stationary RICE has no additional requirements and explain the basis of the exclusion. By 40 CFR 63.6645(c), the initial notification should be submitted no later than 120 days after startup(since 40 CFR 63.6595(a)(3) states startup is when compliance begins).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
		na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The Permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
		na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
		na	Boiler MACT: 40 CFR 63.7545(a)	na	The Permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
		na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
		na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).
		na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
		na	Boiler MACT: 40 CFR 63.7550(a)	na	The Permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
		na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the Permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
		na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
		na	Boiler MACT: 40 CFR 63.7550(h)	na	The Permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
		na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
		na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
		na	Boiler MACT: 40 CFR 63.7545(a)	na	The permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
		na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
		na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).
		na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
		na	Boiler MACT: 40 CFR 63.7550(a)	na	The permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
		na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.
		na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
		na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
		na	Boiler MACT: 40 CFR 63.7550(h)	na	The permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).

Section V.5: Testing Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
EU 2n	Indirect Heat Exchanger #2 Dry-Bottom, Wall-Fired Unit Primary Fuel: Pulverized Coal Secondary Fuel: Natural Gas Startup Fuel: No. 2 Fuel Oil and Natural Gas				
			40 CFR 60 Subpart UUUUb	Testing requirements pursuant to 40 CFR 60 Subpart UUUUb to be provided in correlation with submittal by KDAQ of the final federally enforceable State plan by May 11, 2026.	
EU 17	NG-Fired Dew Point Heater No. 1 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 11.65 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
		na	Boiler MACT: 40 CFR 63.7540(a)	na	The permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
		na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	The permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The Permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.
		na	Boiler MACT: 40 CFR 63.7540(a)(13)	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
EU 18	NG- & Oil-Fired Combustion Turbine (Unit 3) Siemens 5000F with HRSG and ST				
EU 19	NG- & Oil-Fired Combustion Turbine (Unit 4) Siemens 5000F CT with HRSG and ST				
		na	40 CFR 60.4405	Initial Performance Test	Perform the initial performance test required under 40 CFR 60.8 in the alternative manner specified by 40 CFR 60.4405(a) through (d) as the permittee elects to install and certify a NOx-diluent CEMS under 40 CFR 60.4345.
		Formaldehyde	40 CFR 63.6110(a)	Initial Performance Test	The permittee must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of NESHAP YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in 40 CFR 63.6095 and according to the provisions in 40 CFR 63.7(a)(2).
		Formaldehyde	40 CFR 63.6110(b)	Initial Performance Test	The permittee is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in 40 CFR 63.6110(b)(1) through (b)(5).
		Formaldehyde	40 CFR 63.6115	Subsequent Performance Tests	Subsequent performance tests for formaldehyde must be performed on an annual basis as specified in Table 3 of 40 CFR 63 Subpart YYYY.
		Formaldehyde	40 CFR 63.6120(a)-(b)	Initial and Subsequent Performance Tests	Conduct each performance test in Table 3 of 40 CFR 63 Subpart YYYY that applies.
		Formaldehyde	40 CFR 63.6120(c)	Initial and Subsequent Performance Tests	Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The permittee may not conduct performance tests during periods of malfunction. The permittee must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the permittee shall make available to the Division such records as may be necessary to determine the conditions of performance tests.
		Formaldehyde	40 CFR 63.6120(d)	Initial and Subsequent Performance Tests	Conduct three separate test runs for each performance test, and each test run must last at least 1 hour.
			40 CFR 60 Subpart TTTTa	40 CFR 60 Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit conditions are not provided.	

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
EU 20	NG-Fired Auxiliary Boiler with ULNB and Oxidation Catalyst, Manufacturer/Make/Model TBD, Max Heat Input 78.3 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
		na	Boiler MACT: 40 CFR 63.7540(a)	na	The permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
		na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	The permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.
		na	Boiler MACT: 40 CFR 63.7540(a)(13)	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.
EU 23	NG-Fired Dew Point Heater No. 2 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
		na	Boiler MACT: 40 CFR 63.7540(a)	na	The permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
		na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	The permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The Permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.
		na	Boiler MACT: 40 CFR 63.7540(a)(13)	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.
EU 24	NG-Fired Dew Point Heater No. 3 w/ LNBs, Manufacturer/Make/Model TBD, Max Heat Input 9.13 MMBtu/hr (HHV)				
		na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
		na	Boiler MACT: 40 CFR 63.7540(a)	na	The permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
		na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	The permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.
		na	Boiler MACT: 40 CFR 63.7540(a)(13)	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.

Section V.6: Notes, Comments, and Explanations
Any PSD permit requirements and associated compliance demonstration methodologies derived from 401 KAR 51:017 are documented in the suggested permit included with this application for the Cooper Project and not reiterated on this DEP7007 V form.

Division for Air Quality
300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007DD

Insignificant Activities

___ Section DD.1: Table of Insignificant Activities
___ Section DD.2: Signature Block
___ Section DD.3: Notes, Comments, and Explanations

Source Name: East Kentucky Power Cooperative, Inc.

KY EIS (AFS 21- 161-00009

Permit #: V-18-027

Agency Interest (AI) ID: 3808

Date: 1/24/2025

Section DD.1: Table of Insignificant Activities

*Identify each activity with a unique Insignificant Activity number (IA #); for example: 1, 2, 3… etc.

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
IA - 01	Storage vessels containing petroleum or organic liquids with a capacity of less than 10,567 gallons, providing (a) the vapor pressure of the stored liquid is less than 1.5 psia at storage temperature, or (b) vessels greater than 580 gallons with stored liquids having greater than 1.5 psia vapor pressure are equipped with a permanent submerged fill pipe		N/A	
IA - 02	Storage vessels containing inorganic aqueous liquids, except inorganic acids with boiling points below the maximum storage temperature at atmospheric pressure.		N/A	
IA - 03	#2 oil-fired space heaters or ovens rated at less than two million BTU per hour actual heat input, provided the maximum sulfur content is less than 0.5% by weight.		N/A	
IA - 04	Machining of metals, providing total solvent usage at the source for this activity does not exceed 60 gallons per month.		N/A	
IA - 05	Volatile organic compound and hazardous air pollutant storage containers, as follows: (a) Tanks, less than 1,000 gallons, and throughput less than 12,000 gallons per year; (b) Lubricating oils, hydraulic oils, machining oils, and machining fluids		N/A	
IA - 06	Machining where an aqueous cutting coolant continuously floods machining interface.		N/A	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
IA - 07	Degreasing operations, using less than 145 gallons per year.		N/A	
IA - 08	Maintenance equipment, not emitting HAPs: brazing, cutting torches, soldering, welding.		N/A	
IA - 09	Underground conveyors.		401 KAR 63:010	
IA - 10	Coal bunker and coal scale exhausts.		401 KAR 63:010	
IA - 11	Blowdown (sight glass, boiler, compressor, pump, cooling tower).		N/A	
IA - 12	On-site fire and emergency response training.		N/A	
IA - 13	Grinding and machining operations vented through fabric filters, scrubbers, mist eliminators, or electrostatic precipitators (e.g., deburring, buffing, polishing, abrasive blasting, pneumatic conveying, woodworking).		401 KAR 63:010	
IA - 14	Vents from ash transport systems not operated at positive pressure.		N/A	
IA - 15	Wastewater treatment (for stream less than 1% oil and grease).		N/A	
IA - 16	Sanitary sewage treatment.		N/A	
IA - 17	Heat exchanger cleaning and repair.		N/A	
IA - 18	Equipment used exclusively for forging, pressing, drawing, stamping, spinning, or extruding metals. This does not include emissions due to quenching activities.		N/A	
IA - 19	Repair and maintenance of ESP, fabric filters, etc.		N/A	
IA - 20	Ash handling, ash pond and ash pond maintenance		401 KAR 63:010	
IA - 21	Laboratory fume hoods and vents used exclusively for chemical or physical analysis, or for “bench scale production” R&D facilities		N/A	
IA - 22	Covered conveyors for coal or coke that convey less than 200 tons per day		401 KAR 63:010	
IA - 23	EU 05 & 09 - Fly ash loadout systems (Silos A, B & C) configured for either railcar or truck		401 KAR 63:010	
IA - 24	Wood Unloading Area (600 tph)		401 KAR 63:010	
IA - 25	Portable Backup Conveyer		401 KAR 63:010	
IA - 26	DusTreat CF9156 in 850 gallon tank		401 KAR 63:010	
IA - 27	DusTreat DC6109 in 300 gallon tote		401 KAR 63:010	
IA - 28	Powdered Activated Carbon (PAC) System (500 lb./hr. max)		401 KAR 59:010	
IA - 29	19% aqueous ammonia tank(s)	TBD	N/A	KDAQ-approved IA #4 -- Storage vessels containing inorganic aqueous liquids
	NOTE: Blue font are existing IAs. New Insignificant Activities being added to Section C of the Title V permit via this Cooper Project permit action are shown in green font.			

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions

Section DD.2: Signature Block

I, THE UNDERSIGNED, HEREBY CERTIFY UNDER PENALTY OF LAW, THAT I AM A RESPONSIBLE OFFICIAL, AND THAT I HAVE PERSONALLY EXAMINED, AND AM FAMILIAR WITH, THE INFORMATION SUBMITTED IN THIS DOCUMENT AND ALL ITS ATTACHMENTS. BASED ON MY INQUIRY OF THOSE INDIVIDUALS WITH PRIMARY RESPONSIBILITY FOR OBTAINING THE INFORMATION, I CERTIFY THAT THE INFORMATION IS ON KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE OR INCOMPLETE INFORMATION, INCLUDING THE POSSIBILITY OF FINE OR IMPRISONMENT.

Jerry Purvis	1/27/2025
Authorized Signature	**Date**
Jerry Purvis	Vice President, Environmental Affairs
Type/Print Name of Signatory	**Title of Signatory**

Section DD.3: Notes, Comments, and Explanations
Refer to prior applications for emission calculations for existing insignificant activities not affected by this project.

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007EE

Internal Combustion Engines

___ Section EE.1: General Information
___ Section EE.2: Operating Information
___ Section EE.3: Design Information
___ Section EE.4: Fuel Information
___ Section EE.5: Emission Factor Information
___ Section EE.6: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG

___ Attach EPA certification of the engine

Source Name: East Kentucky Power Cooperative, Inc.
KY EIS (AFS) #: 21- 161-00009
Permit #: V-18-027
Agency Interest (AI) ID: 3808
Date: 1/24/2025

Section EE.1: General Information

Emission Unit #	Emission Unit Name	Control Device ID	Stack ID	Manufacturer	Model Number	Model Year	Date of Manufacture	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Date Reconstructed/ Modified	List Applicable Regulations
EU 21	1.25 MW Generator/Engine	na	S-21	TBD -- see EE.6				01/2027	na	NSPS IIII, RICE MACT, 401 KAR 51:017
EU 22	310 HP Diesel Pump/Engine	na	S-22	TBD -- see EE.6				01/2027	na	NSPS IIII, RICE MACT, 401 KAR 51:017

Section EE.2: Operating Information

Emission Unit #	**Engine Purpose** (Identify if Non-Emergency, Emergency,Fire/Water Pump, Black-start engine for combustion turbine, Engine Testing)	**Hours Operated**	**Is this engine a rental?** *(Yes/No)*	**Rental Time Period** *(hrs)*	**Alternate Operating Scenarios** (Describe any operating scenarios in which the engine may be used in a different configuration)
EU 21	Emergency Electrical Generator Power	Estimated maximum of 500 hr/yr	No	na	na
EU 22	Fire/Water Pump	Estimated maximum of 500 hr/yr	No	na	na

Section EE.3: Design Information

Emission Unit #	Engine Type (Identify all that apply: Commercial, Institutional, Stationary, Non-Road)	Ignition Type (Identify if either Compression or Spark Ignition)	Engine Family (Identify all that apply: 2-stroke, 4-stroke, Rich Burn, Lean Burn)	Maximum Engine Power *(bhp)*	Maximum Engine Speed *(rpm)*	Total Displacement *(L)*	Number of Cylinders
EU 21	Stationary	Compression	TBD	2,200	TBD	TBD	TBD
EU 22	Stationary	Compression	TBD	310	TBD	TBD	TBD

Section EE.4: Fuel Information

Emission Unit #	Identify if Primary, Secondary, or Tertiary Fuel	Fuel Type (Identify if Diesel, Gasoline, Natural Gas, Liquefied Petroleum Gas (LPG), Landfill/Digester Gas, or Other)	Fuel Grade	Percent Time Used *(%)*	Maximum Fuel Consumption	Heat Content	Sulfur Content *(%)*	SCC Code	SCC Units
EU 21	Primary	Diesel	ULSD	100	0.113 Mgal/hr	136.20 MMBtu/Mgal	0.0015%	20100102	Mgal
EU 22	Primary	Diesel	ULSD	100	0.016 Mgal/hr	136.20 MMBtu/Mgal	0.0015%	20100102	Mgal

Section EE.5: Emission Factor Information

Emission factors expressed here are based on the potential to emit.

Emission Unit #	Fuel	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor
EU 21	Diesel				
		NOX	199.388	lb/Mgal	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW
		CO	111.955	lb/Mgal	Tier 2 Emission Standards per NSPS IIII
		VOC	5.330	lb/Mgal	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW
		PT	6.397	lb/Mgal	Tier 2 Emission Standards per NSPS IIII
		PM10	6.397	lb/Mgal	Tier 2 Emission Standards per NSPS IIII
		PM2.5	6.397	lb/Mgal	Tier 2 Emission Standards per NSPS IIII
		SO2	0.208	lb/Mgal	AP-42 Table 3.4-1
		CO2	22501.405	lb/Mgal	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
		CH4	0.913	lb/Mgal	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
		N2O	0.183	lb/Mgal	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
		Benzene	0.106	lb/Mgal	AP-42 Table 3.4-3
		Toluene	0.039	lb/Mgal	AP-42 Table 3.4-3
		Xylenes	0.026	lb/Mgal	AP-42 Table 3.4-3

Emission Unit #	Fuel	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor
EU 22	Diesel				
		NOX	118.351	lb/Mgal	= 4 g/kW-hr * 0.925 / 1.341 hp/kW
		CO	111.529	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
		VOC	9.598	lb/Mgal	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW
		PT	6.434	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
		PM10	6.434	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
		PM2.5	6.434	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
		SO2	0.208	lb/Mgal	AP-42 Table 3.4-1 (S is sulfur content in %)
		CO2	22501.405	lb/Mgal	40 CFR 98, Subpart C, Table C-1
		CH4	0.913	lb/Mgal	40 CFR 98, Subpart C, Table C-2
		N2O	0.183	lb/Mgal	40 CFR 98, Subpart C, Table C-2
		Benzene	0.128	lb/Mgal	AP-42 Table 3.3-2
		Toluene	0.056	lb/Mgal	AP-42 Table 3.3-2
		Xylenes	0.039	lb/Mgal	AP-42 Table 3.3-2

Section EE.6: Notes, Comments, and Explanations
EE.2 Form - In a memo from EPA Air Quality and Planning Standards Director John S. Seitz to the regional directors of Air and Radiation, “Calculating Potential to Emit (PTE) for Emergency Generators”, dated September 6, 1995, EPA formalized its position that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.
Construction of equipment associated with this project is not targeted to commence until January 2027. The specific vendors and model numbers of the engines planned for installation will not be known until farther in the project schedule.

Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

(502) 564-3999

DEP7007GG
Control Equipment

Additional Documentation
___ Complete Sections GG.1 through GG.12, as applicable
___ Attach manufacturer's specifications for each control device
___ Complete DEP7007AI

Source Name: East Kentucky Power Cooperative, Inc.

KY EIS (AFS) #: 21- 161-00009

Permit #: V-18-027

Agency Interest (AI) ID: 3808

Date: 1/24/2025

Section GG.1: General Information - Control Equipment

Control Device ID #	Control Device Name	Cost	Manufacturer	Model Name/ Serial #	Date Installed	Inlet Gas Stream Data For All Control Devices: Temperature (°F)	Flowrate (scfm @ 68°F)	Average Particle Diameter (μm)	Particle Density (lb/ft³) or Specific Gravity	Gas Density (lb/ft³)	Inlet Gas Stream Data For Condensers, Adsorbers, Afterburners, Incinerators, Oxidizers Only: Gas Moisture Content (%)	Gas Composition	Fan Type	Equipment Operational Data For All Control Devices: Pressure Drop Range (in. H_2O)	Pollutants Collected/ Controlled	Pollutant Removal (%)
U3-C1	Oxidation Catalyst	na	See GG.12		03/2030	~600-1,200	na	na	na	na	na	na	na	~0.5-1.0	CO VOC	50.0% ,30.0%
U3-C2	SCR	na	See GG.12		03/2030	~575-625	na	na	na	na	na	na	na	~0.6-1.0	NOX	86.7%
U4-C1	Oxidation Catalyst	na	See GG.12		03/2030	~600-1,200	na	na	na	na	na	na	na	~0.5-1.0	CO VOC	50.0% ,30.0%
U4-C2	SCR	na	See GG.12		03/2030	~575-625	na	na	na	na	na	na	na	~0.6-1.0	NOX	86.7%
TBD	Mist Eliminator	na	See GG.12		03/2030	na	na	na	na	na	na	na	na	na	PM	Drift Loss = 0.0005%

Section GG.10: Selective Catalytic Reduction (SCR) / Selective Non-catalytic Reduction (SNCR)

Control Device ID #	Identify all Emission Units and Control Devices that Feed to SCR/SNCR	Type (SCR/SNCR)	Gas Composition	Injection Grid Design (e.g. honeycomb)	Design Temperature Range		Reagent			Maximum Design Ammonia Slip (ppm)	SCR Only			
								Injection Rate			Catalyst			
					Min (°F)	Max (°F)	Type	Min (lb/hr)	Max (lb/hr)		Composition	Volume (ft^3)	Weight (lb)	Replacement Schedule
U3-C2	Unit 3 Gas Turbine	SCR	Refer to Section 4 in Appendix B	na	~550	~700	NH_3	38.52	120.47	5	TiO_2 ceramic substrate with transition metals such as Vanadium, Tungsten, and Molybdenum as activation sites	TBD	TBD	Expected to be scheduled seven to ten years dependent upon actual degradation.
U4-C2	Unit 4 Gas Turbine	SCR	Refer to Section in Appendix B	na	~550	~700	NH_3	38.52	120.47	5	TiO_2 ceramic substrate with transition metals such as Vanadium, Tungsten, and Molybdenum as activation sites	TBD	TBD	Expected to be scheduled seven to ten years dependent upon actual degradation.

Section GG.11: Other Control Equipment

Control Device ID #	Identify all Emission Units and Control Devices that Feed to Control Equipment	**Type of Control Equipment** (provide description and a diagram with dimensions)
U3-C1	Unit 3 Gas Turbine	Oxidation Catalyst - Refer to Process Flow Diagram in Appendix A
U4-C1	Unit 4 Gas Turbine	Oxidation Catalyst - Refer to Process Flow Diagram in Appendix A
TBD	CCGT Cooling Tower	Integrated Mist Eliminator with Drift Loss Specification of no greater than 0.0005%

Section GG.12: Notes, Comments, and Explanations
Construction of equipment associated with this project is not targeted to commence until January 2027. The specific vendors and model numbers of air pollution control equipment planned will not be known until farther in the project schedule.

Division for Air Quality 300 Sower Boulevard Frankfort, KY 40601 (502) 564-3999	**DEP7007HH** Haul Roads _____ Section HH.1: Haul Roads _____ Section HH.2: Yard Area _____ Section HH.3: Notes, Comments, and Explanations	**Additional Documentation** ___ Complete DEP7007AI, DEP7007N and DEP7007V ___ SDS for dust suppressant

Source Name: East Kentucky Power Cooperative, Inc.

KY EIS (AFS) #: **21-** 161-00009

Permit #: V-18-027

Agency Interest (AI) ID: 3808

Date: 1/24/2025

Section HH.1: Haul Roads

HH.1A Unpaved Haul Roads:

Average Number of Days in a Year with 0.01 inches of Precipitation (P): na Days

Mean Vehicle Weight (W): na Tons

Surface Material Silt Content (s): na %

Haul Road Length: na Miles

Maximum Vehicle Miles Traveled in a Year: ________ Miles

Describe the dust control method for unpaved haul road(s): (If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)	na

Emission factor: ________

HH.1B Paved Haul Roads:

Average Number of Days in a Year with 0.01 inches of Precipitation (P): 137 Days

Mean Vehicle Weight (W): 24.1-34.4 Tons

Road Surface Silt Loading (sL): 0.6 (G/M^2)

Haul Road Length: 4.67 Miles

Maximum Vehicle Miles Traveled in a Year: ____ Miles

Describe the dust control method for paved haul road(s):
(If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)

Periodic sweeping

Section HH.2: Yard Area (Aggregate Handling And Storage Piles):

Average Number of Days in a Year with 0.01 inches of Precipitation (P): na Days

Mean Wind Speed (U): na MPH

Material Moisture Content (M): na %

Describe the dust control method for yard area:
(If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)

na

Section HH.3: Notes, Comments, and Explanations

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ **New** ☒ **Revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
John Sherman Cooper Power Station	KY	1384

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
Emission Unit 01 (Unit 1)	Yes
Emission Unit 02 (Unit 2)	Yes
Emission Unit 18 (Unit 3)	Yes
Emission Unit 19 (Unit 4)	Yes

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission

of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with

any other provision of the Act, including the provisions of title I of the Act relating

STEP 3, Cont'd.

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jerry Purvis, Vice President, Environmental Affairs	
Signature *Jerry Purvis*	Date 1/27/2025

APPENDIX D. RBLC SEARCH RESULTS

Table D-1.1 Summary of NOx BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	NO_X Limit	Units	Averaging Period	Fuel Oil NO_X Limit	Units	Control
AK-0088	Alaska LNG Liquefaction Facility	Six Simple Cycle Gas-Fired Turbines	7/7/2022	1,113	MMBtu/hr (each)	2	ppmvd @ 15% O_2	3 Hours	N/A	N/A	SCR, DLN combustors, good combustion practices
AK-0088	Alaska LNG Liquefaction Facility	Four Combined-Cycle Combustion Turbines	7/7/2022	384	MMBtu/hr	2	ppmvd @ 15% O_2	3 Hours			SCR, DLN combustors, good combustion practices
AL-0328	Alabama Power Compamy Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	2	ppmvd @ 15% O2	3 Hours	N/A	N/A	SCR
AL-0329	Colbert Combustion Turbine Plant	Three Simple Cycle Gas-Fired Turbines	9/21/2021	229	MW (each)	9	ppmvd @ 15% O2	3 Hours			None indicated
CA-1238	Puente Power Plant	One Simple-Cycle Gas-Fired Turbine	10/13/2016	262	MW (each)	2.5	ppmvd @ 15% O2	1 Hour	N/A	N/A	None indicated
CA-1251	Palmdale Energy Project	2-on-1 SGT6-5000F Combined-Cycle Gas-Fired Turbines	4/25/2015	645	MW (total)	2	ppmvd @ 15% O2	1 Hour			SCR and DLN combustors
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	2	ppmvd @ 15% O2	1 Hour	5	ppmvd @ 15% O2 (ULSD)	SCR and DLN combustors. Wet-injection when firing ULSD.
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	2	ppmvd @ 15% O2	1 Hour	4	ppmvd @ 15% O2 (ULSD)	SCR
FL-0354	Lauderdale Plant	Five GE 7F.05 Gas-Fired Turbines	8/25/2015	200	MW (each)	9	ppmvd @ 15% O2	24 Hours	42	ppm (ULSD)	DLN Combustors, good combustion practices. Wet-injection when firing ULSD.
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	2	ppmvd @ 15% O2	24 Hours	8	ppm (ULSD)	SCR and DLN combustors. Wet-injection when firing ULSD.
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	2	ppmvd @ 15% O2	24 Hours	N/A	N/A	SCR and DLN combustors.
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	2	ppmvd @ 15% O2	30-day rolling	174.3	lb/hr (SUSD)	SCR and DLN combustors.
IL-0121	Invenergy Nelson Expansion	Two Simple-Cycle Gas-Fired Turbines	9/27/2016	190	MW (each)	9	ppmvd @ 15% O2	Not indicated	42	ppm (ULSD)	DLN Combustors, good combustion practices. Wet-injection when firing ULSD.
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2	ppmvd @ 15% O2	3 Hours	5	ppm (ULSD)	SCR and DLN. Wet-injection when firing ULSD.
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	2	ppmvd @ 15% O2	3 hours	2	ppmvd (1-hr avg.)	SCR and DLN combustors
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	2	ppmvd @ 15% O2	3 hours	2	ppmvd (1-hr avg.)	SCR and DLN combustors
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	2	ppmvd @ 15% O2	3 Hours	N/A	N/A	SCR and DLN combustors.
LA-0316	Cameron LNG Facility	Nine Simple-Cycle Gas-Fired Turbines	2/17/2017	1,069	MMBtu/hr (each)	15	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices
LA-0327	Washington Parish Energy Center	Two Simple-Cycle Gas-Fired Turbines	5/23/2018	2,201	MMBtu/hr (each)	9	ppmvd @ 15% O2	30-day rolling	86.38	lb/hr (SUSD)	DLN combustors, good combustion practices
LA-0331	Calcasieu Pass LNG	Three Simple Cycle Gas-Fired Turbines	9/21/2018	927	MMBtu/hr (each)	9	ppmvd @ 15% O2	30-day rolling	N/A	N/A	DLN Combustors, good combustion practices, natural gas combustion
LA-0331	Calcasieu Pass LNG	5-on-2 Combined-Cycle Gas-Fired Turbines	9/21/2018	710	MW (total)	2.5	ppmvd @ 15% O2	30-day rolling	N/A	N/A	SCR, DLN combustors, good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2	ppmvd @ 15% O2	24 Hours	N/A	N/A	SCR and DLN combustors.
LA-0364	FG LA Complex	2 Combined-Cycle Gas-Fired Turbines	1/6/2020	2,222	MMBtu/hr (each)	2	ppmvd @ 15% O2	12-month rolling	N/A	N/A	SCR, DLN combustors, good combustion practices
LA-0365	Big Cajun I Power Plant	2 Combined-Cycle Gas-Fired Turbines	6/27/2019	120	MW (each)	23	ppmvd @ 15% O2	3 Hours	175.4	tpy	DLN and wet injection
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	2	ppmvd @ 15% O2	1 Hour	N/A	N/A	SCR, DLN combustors, good combustion practices
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	2	ppmvd @ 15% O2	1 Hour	0.0074	lb/MMBtu (1-hr avg.)	SCR and DLN combustors
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	2	ppmvd @ 15% O2	3-Hours	123	lb/SUSD Event	SCR and DLN combustors

Table D-1.1 Summary of NOx BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	NO_X Limit	Units	Averaging Period	Fuel Oil NO_X Limit	Units	Control
MD-0042	Wildcat Point Generation Facility	Two Combined-Cycle Gas-Fired Turbines	4/8/2014	1,000	MW (total)	2	ppmvd @ 15% O2	3-Hours	870	lb/SUSD Event	SCR, DLN combustors, pipeline-quality natural gas
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	2	ppmvd @ 15% O2	3-Hours	42	ppmvd (3-hr avg.)	SCR and DLN combustors
MD-0046	Keys Energy Center	Two Siemens SGT6-500FEE Combined-Cycle Gas-Fired Turbines	10/31/2014	235	MW (each)	2	ppmvd @ 15% O2	3-Hours	42	ppmvd (3-hr avg.)	SCR, DLN combustors, good combustion practices
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	3	ppmvd @ 15% O2	24-Hours	286	lb/hr (SUSD)	SCR and DLN combustors
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	3	ppmvd @ 15% O2	24-Hours	21.4	lb/hr (excl. SUSD)	SCR and DLN combustors
MI-0431	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/26/2018	4,161	MMBtu/hr (each)	2	ppmvd @ 15% O2	24-Hours			SCR and DLN combustors
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	2	ppmvd @ 15% O2	24-Hours			SCR and DLN combustors
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	2	ppmvd @ 15% O2	24-Hours			SCR and DLN combustors
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	2	ppmvd @ 15% O2	24-Hours			SCR and DLN combustors.
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2	ppmvd @ 15% O2	24-Hours			SCR, DLN combustors, good combustion practices
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	2	ppmvd @ 15% O2	24-Hours			SCR
NJ-0081	PSEG Fossil LLC Sewaren Station	Two Combustion Turbines	3/7/2014	625	MW (each)	2	ppmvd @ 15% O2	3-Hours			SCR, DLN
NJ-0082	West Deptford Energy Station	One Combined-Cycle Combustion Turbine	7/18/2014	427	MW	2	ppmvd @ 15% O2	3-Hours			SCR, use of natural gas as primary fuel
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	2	ppmvd @ 15% O2	3-Hours	4	ppmvd @ 15% O2 (3-hr rolling)	SCR, DLN
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	2	ppmvd @ 15% O2	3-Hours	4	ppmvd @ 15% O2 (3-hr rolling)	SCR, DLN, and use of Natural gas as Primary fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	2	ppmvd @ 15% O2	1 Hour			SCR and DLN combustors
OH-0363	NTE Ohio, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	11/5/2014	3278.5	MMBTu/hr	2	ppmvd @ 15% O2	1 Hour			Natural Gas, low NOX burner, SCR
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	2	ppmvd @ 15% O2	3-Hours			DLN and SCR
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	2	ppmvd @ 15% O2	24-Hours			DLN, SCR
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	2	ppmvd @ 15% O2	1 Hour	5	ppmvd @ 15% O2 (2-hr avg)	DLN, SCR, wet injection
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	2	ppmvd @ 15% O2	1 Hour			DLN, SCR
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	2	ppmvd @ 15% O2	1 Hour			DLN. SCR
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	2	ppmvd @ 15% O2	1 Hour			DLN, SCR
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	2	ppmvd @ 15% O2	1 Hour			DLN, SCR
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	2	ppmvd @ 15% O2	1 Hour			DLN, SCR
OR-0050	Troutdale Energy Center	GE LMS100 Simple-Cycle Gas-Fired Turbines	3/5/2014	1,690	MMBtu/hr (each)	2.5	ppmvd @ 15% O2	3 Hours	3.8	ppmvd @ 15% O2	H_2O Injection, SCR, limit SUSD time

Table D-1.1 Summary of NOx BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	NO_X Limit	Units	Averaging Period	Fuel Oil NO_X Limit	Units	Control
PA-0298	Good Springs NGCC Facility	Siemens 5000 Combined-Cycle Turbine	3/4/2014	346	MW	2	ppmvd @ 15% O2	1 Hour			SCR
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	2	ppmvd @ 15% O2	1 Hour			SCR, DLN, good combustion practice
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	2	ppmvd @ 15% O2	Not indicated			SCR, DLN, good combustion practice, low sulfur fuels
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	2	ppmvd @ 15% O2	1 Hour			DLN, SCR, exclusive natural gas
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	2	ppmvd @ 15% O2	12 month rolling	6	ppmvd @ 15% O2	DLN, SCR, good combustion and operating practices
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	2	ppmvd @ 15% O2	24-Hours			DLN, SCR, Good engineering practices
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			None indicated
PA-0316	Renovo Energy Center, LLC	Two 1-on-1 Combustion Turbine	1/26/2018	500	MW	2	ppmvd @ 15% O2	1 Hour			SCR
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	2	ppmvd @ 15% O2	Not indicated			SCR
PA-0333	Esc Tioga County Power LLC/Elec Pwr Gen Fac	One 1-on-1 Natural Gas Combustion Turbine	8/20/2019	635	MW	2	ppmvd @ 15% O2	1 Hour			SCR, Catalytic Oxidizer
PA-0334	Renovo Energy Center LLC/Renovo Plt	Two 1-on-1 Combined cycle combustion turbine	4/29/2021	3,940	MMBtu/hr	2	ppmvd @ 15% O2	1 Hour	4	ppmvd @ 15% O2 (1hr)	SCR, oxidation catalyst
TN-0162	TVA Johnsonville Cogeneration	One 1-on-1 Gas Fired Combustion Turbine	4/19/2016	1,339	MMBTu/hr	2	ppmvd @ 15% O2	30-day rolling	8	ppmvd @ 15% O2 (15-day)	SCR, good combustion design and practices
TX-0688	Sr. Berton Electric Generating Station	Two Simple-Cycle Gas-Fired Turbines	12/19/2014	215-359	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	Good combustion practices, natural gas. SCR during CC operation.
TX-0714	Sr. Berton Electric Generating Station	Two 1-on-1 Gas Fired Combustion Turbines	12/19/2014	240	MW	2	ppmvd @ 15% O2	24-Hours			SCR
TX-0689	Cedar Bayou Electric Generation Station	Two 1-on-1 Gas Fired Combustion Turbines	8/29/2014	215-263	MW (each)	2	ppmvd @ 15% O2	24-Hours			DLN, SCR
TX-0693	Antelope Elk Energy Center	One GE 7F 5 Series Simple-Cycle Gas-Fired Turbine	4/22/2014	202	MW	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0694	Indeck Wharton Energy Center	Three Simple Cycle Gas-Fired Turbines	2/2/2015	214-227	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0695	Ector County Energy Center	Two GE 7FA.03 Simple-Cycle Gas-Fired Turbines	8/1/2014	180	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0696	Roan's Prarier Generating Station	Two Simple-Cycle Gas-Fired Turbines	9/22/2014	600	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0710	Victoria Power Station	Two 2-on-1 Combined-Cycle Combustion Turbines	12/1/2014	197	MW	2	ppmvd @ 15% O2	24-Hours			SCR
TX-0713	Tenaska Brownsville Generating Station	Two 2-on-1 Combined-Cycle Gas Turbine	4/29/2014	274	MW	2	ppmvd @ 15% O2	24-Hours			SCR
TX-0730	Colorado Bend Energy Center	Two 1-on-1 Combustion Turbine	4/1/2015	1,100	MW	2	ppmvd @ 15% O2	24-Hours			SCR and Oxidation Catalyst
TX-0734	Clear Springs Energy Center	Three GE 7FA.04 Simple-Cycle Gas-Fired Turbines	5/8/2015	183	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0764	Nacogoches Power Electric Generating Plant	One Siemens F5 Simple-Cycle Gas-Fired Turbine	10/14/2015	232	MW	9	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices, limited operation
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2	ppmvd @ 15% O2	24-Hours			SCR
TX-0768	Shawnee Energy Center	Two Simple-Cycle Gas-Fired Turbines	10/9/2015	230	MW (each)	9	ppmvd @ 15% O2	Not indicated			DLN combustors, good combustion practices
TX-0769	Van Alstyne Energy Center	Three GE 7FA.04 Simple-Cycle Gas-Fired Turbines	10/27/2015	183	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices

Table D-1.1 Summary of NOx BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	NO_X Limit	Units	Averaging Period	Fuel Oil NO_X Limit	Units	Control
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2	ppmvd @ 15% O2	24-Hours			SCR
TX-0777	Union Valley Energy Center	Three GE 7FA.04 Simple-Cycle Gas-Fired Turbines	12/9/2015	183	MW (each)	9	ppmvd @ 15% O2	3 Hours	N/A	N/A	DLN combustors, good combustion practices
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	9	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	2	ppmvd @ 15% O2	Not indicated			SCR
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	2	ppmvd @ 15% O2	Not indicated			SCR
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	9	ppmvd @ 15% O2	24-Hours			DLN combustors, good combustion practices
TX-0794	Hill County Generating Station	Simple Cycle Gas-Fired Turbines	4/7/2016	171	MW (each)	9	ppmvd @ 15% O2	3 Hours	42	ppmvd @ 15% O2 (3hr)	DLN combustors, good combustion practices, water injection (ULSD)
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	2	ppmvd @ 15% O2	3-Hours			SCR, DLN
TX-0826	Mustang Station	Simple Cycle Gas-Fired Turbines	8/16/2017	162.8	MW	9	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices
TX-0833	Jackson County Generators	Four Simple-Cycle Gas-Fired Turbines	1/26/2018	230	MW (each)	9	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2	ppmvd @ 15% O2	1-Hour			SCR and DLN burners
TX-0851	Rio Bravo Pipeline Facility	Twelve GE 7EA Simple-Cycle Gas-Fired Turbines	12/17/2018	91	MW (each)	9	ppmvd @ 15% O2	24 Hours	N/A	N/A	DLN Combustors, good combustion practices
TX-0878	LNG Export Terminal	Eight GE 7E Refrigeration and Compression Turbines	9/15/2022		MW						DLN Combustors, good combustion practices
TX-0908	Newman Power Station	One Simple-Cycle Gas-Fired Turbine	8/27/2021	230	MW	2.5	ppmvd @ 15% O2	1 Hour			DLN, SCR
TX-0975	Freestone Peakers Plant	One GE 7FA.05 Simple-Cycle Gas-Fired Turbine	6/13/2024	221	MW	9	ppmvd @ 15% O2	Not indicated	N/A	N/A	DLN combustors, good combustion practices
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	2	ppmvd @ 15% O2	1 Hour			SCR
VA-0326	Doswell Energy Center	Two GE 7FA Simple-Cycle Gas-Fired turbines	10/4/2016	1961	MMBtu/hr (each)	9	ppmvd @ 15% O2	12-month rolling	74.2	lb/hr (12-month rolling)	DLN combustors, good combustion practices
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	2	ppmvd @ 15% O2	1-Hour			DLN burners and SCR
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	2	ppmvd @ 15% O2	1-Hour			DLN burners and SCR
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	2	ppmvd @ 15% O2	1-Hour			DNL, SCR
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	2	ppmvd @ 15% O2	1 Hour			SCR, with ammonia injection, DLN
WI-0300	Nemadji Trail Energy Center	One 1-on-1 Combined Cycle Combustion Turbine	9/1/2020	4,671	MMBTU/hr	2	ppmvd @ 15% O2	24-Hours	6	ppmvd @ 15% O2	SCR, DLN, water injection (ULSD)
WV-0025	Moundsville Combined Cycle Power Plant	Two GE 7FA.04 Combined Cycle Combustion Turbines	11/21/2014	197	MW (each)	2	ppmvd @ 15% O2	1 Hour			SCR, DLN
WV-0028	Waverly Power Plant	Two GE 7FA.004 Simple-Cycle Gas-Fired Turbines	3/13/2018	167.8	MW (each)	9	ppmvd @ 15% O2	Not indicated			DLN combustors, good combustion practices
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	2	ppmvd @ 15% O2	1 Hour			SCR, DLN
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	2	ppmvd @ 15% O2	1 Hour			SCR, DLN
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW	2	ppmvd @ 15% O2	3-Hours			DLN, SCR

Table D-1.2 Summary of CO BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO Limit	Units	Averaging Period	Fuel Oil CO Limit	Units	Control
AK-0088	Alaska LNG Liquefaction Facility	Four Combined-Cycle Combustion Turbines	7/7/2022	384	MMBtu/hr	2	ppmvd @ 15% O2	3 Hours			Oxidation catalyst and good combustion practices
AL-0328	Alabama Power Compamy Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	0.005	lb/MMBtu	3 Hours			Oxidation catalyst
CA-1251	Palmdale Energy Project	2-on-1 SGT6-5000F Combined-Cycle Gas-Fired Turbines	4/25/2015	645	MW (total)	1.5	ppmvd @ 15% O2	1 Hour			Oxidation catalyst
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	0.9	ppmvd @ 15% O2	1 Hour	2	ppmvd @ 15% O2	Oxidation catalyst
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.9	ppmvd @ 15% O2	1 Hour	1.8	ppmvd @ 15% O2	Oxidation catalyst
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	4.3	ppmvd @ 15% O2	3-Hour	10	ppmvd @ 15% O2	Clean burners that prevent CO formation
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	4.3	ppmvd @ 15% O2	3-Hour			Clean burning fuel with good combustion
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	2	ppmvd @ 15% O2	30 Days			Oxidation catalyst
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2	ppmvd @ 15% O2	3-Hour	17	lb/hr	Oxidation catalyst
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	1.5	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	1.5	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
LA-0331	Calcasieu Pass LNG	5-on-2 Combined-Cycle Gas-Fired Turbines	9/21/2018	710	MW (total)	5	ppmvd @ 15% O2	30 Day Rolling			Oxidation Catalyst, Proper Design, Good Combustion Practices.
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2	ppmvd @ 15% O2	24 Hour Rolling			Catalytic Oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.
LA-0364	FG LA Complex	2 Combined-Cycle Gas-Fired Turbines	1/6/2020	2,222	MMBtu/hr	4	ppmvd @ 15% O2	Not indicated			Good combustion practices and catalytic oxidation
LA-0365	Big Cajun I Power Plant	2 Combined-Cycle Gas-Fired Turbines	6/27/2019	120	MW (each)	25	ppmvd @ 15% O2	3 Hours			None indicated
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	2	ppmvd @ 15% O2	24 Hour Rolling			Catalytic oxidation and good combustion practices.
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	2	ppmvd @ 15% O2	1-hr Average			Oxidation catalyst
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	2	ppmvd @ 15% O2	3 Hours			Oxidation catalyst and good combustion practices
MD-0042	Wildcat Point Generation Facility	Two Combined-Cycle Gas-Fired Turbines	4/8/2014	1,000	MW (total)	1.5	ppmvd @ 15% O2	3 Hours			Exclusive use of pipeline-quality natural gas, use of an oxidation catalyst, and efficient CT design
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	2	ppmvd @ 15% O2	3 Hours			Good combustion practices and oxidation catalyst

Table D-1.2 Summary of CO BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO Limit	Units	Averaging Period	Fuel Oil CO Limit	Units	Control
MD-0046	Keys Energy Center	Two Siemens SGT6-500FEE Combined-Cycle Gas-Fired Turbines	10/31/2014	235	MW (each)	2	ppmvd @ 15% O2	3 Hours			Good combustion practices and oxidation catalyst
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	4	ppmvd @ 15% O2	24-hr rolling			Good combustion practices and oxidation catalyst
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	4	ppmvd @ 15% O2	24-hr rolling			Oxidation catalyst and good combustion practices.
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	2	ppmvd @ 15% O2	24-hr rolling			Oxidation catalyst technology and good combustion practices
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	4	ppmvd @ 15% O2	24-hr rolling			Oxidation catalyst technology and good combustion practices
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	0.0045	lb/MMBtu	24-hr rolling			Oxidation catalyst technology and good combustion practices
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2	ppmvd @ 15% O2	24-hr Avg			Oxidation catalyst and good combustion practices
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	2	ppmvd @ 15% O2	24-hr Avg			Oxidation catalyst
NJ-0081	PSEG Fossil LLC Sewaren Station	Two Combustion Turbines	3/7/2014	625	MW (each)	2	ppmvd @ 15% O2	3 Hours			Oxidation catalyst, good combustion practices, and use of natural gas as a clean burning fuel
NJ-0082	West Deptford Energy Station	One Combined-Cycle Combustion Turbine	7/18/2014	427	MW	0.9	ppmvd @ 15% O2	3 Hours			Oxidation catalyst and use of natural gas as a clean burning fuel
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	2	ppmvd @ 15% O2	3 Hours	2	ppmvd @ 15% O2	Oxidation catalyst and good combustion practices
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	2	ppmvd @ 15% O2	3 Hours	3	ppmvd @ 15% O2	Oxidation catalyst and use of clean burning fuels (natural gas and ULSD)
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	2	ppmvd @ 15% O2	1 Hour			Oxidation catalyst and good combustion practices
OH-0363	NTE Ohio, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	11/5/2014	3278.5	MMBtu/hr	2	ppmvd @ 15% O2	Not indicated			Use of natural gas, combustion controls, and catalytic oxidation
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	2	ppmvd @ 15% O2	3 Hours			Oxidation catalyst
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	2	ppmvd @ 15% O2	Hourly avg.	16.15	lb/hr	Good combustion controls and oxidation catalyst
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	2	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst

Table D-1.2 Summary of CO BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO Limit	Units	Averaging Period	Fuel Oil CO Limit	Units	Control
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices as recommended by the manufacturer
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices as recommended by the manufacturer
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	2	ppmvd @ 15% O2	Not indicated			Good combustion practices and oxidation catalyst
PA-0298	Good Springs NGCC Facility	Siemens 5000 Combined-Cycle Turbine	3/4/2014	346	MW	3	ppmvd @ 15% O2	Not indicated			CO catalyst
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	15.9	lb/hr (w/ DB)	3 Hours			Oxidation catalyst and good combustion practice
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	2	ppmvd @ 15% O2	1 Hour			Oxidation catalyst, combustion controls, exclusive natural gas
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, good engineering practice
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
PA-0333	Esc Tioga County Power LLC/Elec Pwr Gen Fac	One 1-on-1 Natural Gas Combustion Turbine	8/20/2019	635	MW	1.5	ppmvd @ 15% O2 (w/ DB)	1 Hour			None indicated
PA-0334	Renovo Energy Center LLC/Renovo Plt	Two 1-on-1 Combined cycle combustion turbine	4/29/2021	3,940	MMBtu/hr	1.5	ppmvd @ 15% O2 (w/ DB)	1 Hour	2	ppmvd @ 15% O2 (1hr)	SCR, catalytic oxidizer
TN-0162	TVA Johnsonville Cogeneration	One 1-on-1 Gas Fired Combustion Turbine	4/19/2016	1,339	MMBTu/hr	2	ppmvd @ 15% O2	30-day Rolling	10	ppmvd @ 15% O2 (30day)	Good combustion design and practices, oxidation catalyst
TX-0714	Sr. Berton Electric Generating Station	Two 1-on-1 Gas Fired Combustion Turbines	12/19/2014	240	MW	2	ppmvd @ 15% O2	12-mo Rolling			Oxidation catalyst
TX-0689	Cedar Bayou Electric Generation Station	Two 1-on-1 Gas Fired Combustion Turbines	8/29/2014	215-263	MW (each)	2	ppmvd @ 15% O2	12-mo Rolling			Oxidation catalyst
TX-0710	Victoria Power Station	Two 2-on-1 Combined-Cycle Combustion Turbines	12/1/2014	197	MW	4	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0713	Tenaska Brownsville Generating Station	Two 2-on-1 Combined-Cycle Gas Trurbine	4/29/2014	274	MW	2	ppmvd @ 15% O2	24-Hour			Oxidation catalyst
TX-0730	Colorado Bend Energy Center	Two 1-on-1 Combustion Turbine	4/1/2015	1,100	MW	4	ppmvd @ 15% O2	3-Hour			SCR and oxidation catalyst
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2	ppmvd @ 15% O2	24-Hour			Oxidation catalyst
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	4 2	ppmvd @ 15% O2	1-Hour Annual			Oxidation catalyst
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	4	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	25	ppmvd @ 15% O2	3-Hour			DLN burners and good combustion practices
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	2	ppmvd @ 15% O2	3-Hour			SCR and DLN burners

Table D-1.2 Summary of CO BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO Limit	Units	Averaging Period	Fuel Oil CO Limit	Units	Control
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0878	LNG Export Terminal	Eight GE 7E Refrigeration and Compression Turbines	9/15/2022		MW	25	ppmvd @ 15% O2	24-Hour			Good combustion practices
TX-0908	Newman Power Station	One Simple-Cycle Gas-Fired Turbine	8/27/2021	230	MW	3	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	1	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	1	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	1.8	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	1	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	2	ppmvd @ 15% O2	Not indicated			Catalytic oxidizer
WI-0300	Nemadji Trail Energy Center	One 1-on-1 Combined Cycle Combustion Turbine	9/1/2020	4,671	MMBTU/hr	1.5	ppmvd @ 15% O2	168-hr	1.5	ppmvd @ 15% O2	Oxidation catalyst and good combustion controls
WV-0025	Moundsville Combined Cycle Power Plant	Two GE 7FA.04 Combined Cycle Combustion Turbines	11/21/2014	197	MW (each)	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and combustion controls
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, good combustion practices
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst, good combustion practices

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

Table D-1.3 Summary of VOC BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted VOC Limit	Units	Averaging Period	Fuel Oil VOC Limit	Units	Control
WI-0300	Nemadji Trail Energy Center	One 1-on-1 Combined Cycle Combustion Turbine	9/1/2020	4,671	MMBTU/hr	0.6	ppmvd @ 15% O2	168 Hour	0.6	ppmvd @ 15% O2	Oxidation catalyst, good combustion control
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.7	ppmvd @ 15% O2	Not indicated	2	ppmvd @ 15% O2	Oxidation catalyst
NJ-0082	West Deptford Energy Station	One Combined-Cycle Combustion Turbine	7/18/2014	427	MW	0.7	ppmvd @ 15% O2	N/A (stack test)			Oxidation catalyst and use of natural gas as a clean burning fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	0.7	ppmvd @ 15% O2	1 Hour			Oxidation catalyst and good combustion practices
VA-0325	Greensville Power Station	One 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.7	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	0.7	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	0.7	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	1	ppmvd @ 15% O2	Not indicated	2	ppmvd @ 15% O2	Oxidation catalyst
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	1	ppmvd @ 15% O2	N/A	2	ppmvd @ 15% O2	Complete combustion
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	1	ppmvd @ 15% O2	N/A (stack test)			Catalytic oxidizer
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	1	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	1	ppmvd @ 15% O2	3-Hour			Oxidation catalyst and good combustion practices
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	1	ppmvd @ 15% O2	N/A (stack test)			Catalytic oxidation and good combustion practices.
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	1	ppmvd @ 15% O2	1-hr Average			Oxidation catalyst
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	1	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	1	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
MD-0046	Keys Energy Center	Two Siemens SGT6-500FEE Combined-Cycle Gas-Fired Turbines	10/31/2014	235	MW (each)	1	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1	ppmvd @ 15% O2	Hourly			
NJ-0081	PSEG Fossil LLC Sewaren Station	Two Combustion Turbines	3/7/2014	625	MW (each)	1	ppmvd @ 15% O2	N/A (stack test)			Oxidation catalyst and use of natural gas as a clean burning fuel
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	1	ppmvd @ 15% O2	N/A	2	ppmvd @ 15% O2 (stack test)	Oxidation catalyst and good combustion practices

Table D-1.3 Summary of VOC BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted VOC Limit	Units	Averaging Period	Fuel Oil VOC Limit	Units	Control
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	1	ppmvd @ 15% O2	3 Hour	2	ppmvd @ 15% O2 (stack test)	Oxidation catalyst and use of natural gas as primary fuel
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	1	ppmvd @ 15% O2	1 Hour	2	ppmvd @ 15% O2 (1hr)	Good combustion controls and oxidation catalyst
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	1	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated			Good combustion controls and oxidation catalyst
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	1	ppmvd @ 15% O2	24-Hour			Good combustion practices and oxidation catalyst
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, combustion controls, exclusive natural gas
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated	2	ppmvd @ 15% O2	Oxidation catalyst, water/steam injection (ULSD), and good combustion practices
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated			None indicated
PA-0316	Renovo Energy Center, LLC	Two 1-on-1 Combustion Turbine	1/26/2018	500	MW	1	ppmvd @ 15% O2	Not indicated			None indicated
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0714	Sr. Berton Electric Generating Station	Two 1-on-1 Gas Fired Combustion Turbines	12/19/2014	240	MW	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	1	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
WV-0025	Moundsville Combined Cycle Power Plant	Two GE 7FA.04 Combined Cycle Combustion Turbines	11/21/2014	197	MW (each)	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, good combustion practices
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	1	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, good combustion practices

Table D-1.3 Summary of VOC BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted VOC Limit	Units	Averaging Period	Fuel Oil VOC Limit	Units	Control
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW	1	ppmvd @ 15% O2	N/A (stack test)			Oxidation catalyst, good combustion practices
LA-0331	Calcasieu Pass LNG	5-on-2 Combined-Cycle Gas-Fired Turbines	9/21/2018	710	MW (total)	1.1	ppmvd @ 15% O2	3 Hour			Catalytic Oxidation, Proper Equipment Design and Good Combustion Practices.
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	1.4	ppmvd @ 15% O2	3 Hour			Good combustion practices along with clean fuels
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	1.5	ppmvd @ 15% O2	Not indicated			Oxidation catalyst, good combustion practices and low sulfur fuels
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	1.5	ppmvd @ 15% O2	Not indicated			Catalytic oxidizer
PA-0334	Renovo Energy Center LLC/Renovo Plt	Two 1-on-1 Combined cycle combustion turbine	4/29/2021	3,940	MMBtu/hr	1.6	ppmvd @ 15% O2 (w/ DB)	Not indicated	2	ppmvd @ 15% O2	SCR, catalytic oxidizer
AK-0088	Alaska LNG Liquefaction Facility	Four Combined-Cycle Combustion Turbines	7/7/2022	384	MMBtu/hr	2	ppmvd @ 15% O2	3 Hour			Oxidation catalyst and good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2	ppmvd @ 15% O2	3 Hour			Catalytic oxidation and good combustion practices for normal operations, and good combustion practices for startup/shutdown operations.
PA-0298	Good Springs NGCC Facility	Siemens 5000 Combined-Cycle Turbine	3/4/2014	346	MW	2	ppmvd @ 15% O2	Not indicated			CO catalyst
TX-0713	Tenaska Brownsville Generating Station	Two 2-on-1 Combined-Cycle Gas Trurbine	4/29/2014	274	MW	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	2	ppmvd @ 15% O2	Not indicated			Oxidation catalyst
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	2	ppmvd @ 15% O2	3-Hour			DLN burners and good combustion practices
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0878	LNG Export Terminal	Eight GE 7E Refrigeration and Compression Turbines	9/15/2022		MW	2	ppmvd @ 15% O2	3-Hour			Good combustion practices
TX-0908	Newman Power Station	One Simple-Cycle Gas-Fired Turbine	8/27/2021	230	MW	2	ppmvd @ 15% O2	Not indicated			Use of natural gas, good combustion practices, and oxidation catalyst
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	2.4	ppmvd @ 15% O2	Hourly			Oxidation catalyst
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	2.4	ppmvd @ 15% O2 (w/ DB)	Not indicated			Oxidation catalyst and good combustion practices
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	3.5	ppmvd @ 15% O2	Not indicated			Oxidation catalyst and good combustion practices
LA-0364	FG LA Complex	2 Combined-Cycle Gas-Fired Turbines	1/6/2020	2,222	MMBtu/hr	4	ppmvd @ 15% O2	Not indicated			Good combustion practices and catalytic oxidation
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	4	ppmvd @ 15% O2	N/A (stack test)			Oxidation catalyst and good combustion practices
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	4	ppmvd @ 15% O2	Hourly			Oxidation catalyst and good combustion practices
TX-0710	Victoria Power Station	Two 2-on-1 Combined-Cycle Combustion Turbines	12/1/2014	197	MW	4	ppmvd @ 15% O2	3-Hour			Oxidation catalyst
TX-0730	Colorado Bend Energy Center	Two 1-on-1 Combustion Turbine	4/1/2015	1,100	MW	4	ppmvd @ 15% O2	3-Hour			SCR and oxidation catalyst

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

Table D-1.4 Summary of PM BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted PM Limit	Units	Averaging Period	Fuel Oil PM Limit	Units	Control
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	0.0062	lb/MMBtu	1-hr Average			None indicated
NJ-0081	PSEG Fossil LLC Sewaren Station	Two Combustion Turbines	3/7/2014	625	MW (each)	8.7 12.7	lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	Not indicated			Use of natural gas as a clean burning fuel
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	0.01	lb/MMBtu	N/A (stack test)			None indicated
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	0.005 0.008	lb/MMBtu (PM_{filt}) lb/MMBtu (PM_{10})	3 Hour N/A (stack test)			Exclusive Use of Pipeline-Quality Natural Gas and Good Combustion Practices
OH-0363	NTE Ohio, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	11/5/2014	3278.5	MMBTu/hr	0.0038	lb/MMBtu (PM)	Not indicated			Exclusive use of natural gas, high efficiency inlet air filters and low NOx burner.
WV-0025	Moundsville Combined Cycle Power Plant	Two GE 7FA.04 Combined Cycle Combustion Turbines	11/21/2014	197	MW (each)	0.0037	lb/MMBtu ($PM_{2.5}$)	Not indicated			Good combustion practices, inlet air filtration, and use of natural gas
CA-1251	Palmdale Energy Project	2-on-1 SGT6-5000F Combined-Cycle Gas-Fired Turbines	4/25/2015	645	MW (total)	0.0048	lb/MMBtu (PM,$PM_{10,2.5}$)	N/A (stack test)			Clean fuel and good combustion practices
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	0.0068	lb/MMBtu (PM)	3 Hour			Good combustion practices along with clean fuels
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	0.0068	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated	0.0272	lb/MMBtu (PM,$PM_{10,2.5}$)	Good combustion practices and low sulfur fuels
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	0.0068	lb/MMBtu ($PM_{10,2.5}$)	Not indicated			Low sulfur fuel
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	0.0063	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated			None indicated
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	0.003 0.0059	lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated			Exclusive natural gas, high-efficiency inlet air filters and DLN
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	0.005	lb/MMBtu (PM)	1 Hour			Good combustion practices and use of pipeline quality natural gas
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	0.0039	lb/MMBtu (w/ DB)	Not indicated			Good combustion practices with use of low ash/sulfur fuels
TN-0162	TVA Johnsonville Cogeneration	One 1-on-1 Gas Fired Combustion Turbine	4/19/2016	1,339	MMBTu/hr	0.005	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated	0.015	lb/MMBtu	Good combustion design and practices
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.003	lb/MMBtu	N/A (stack test)			Low sulfur/carbon fuel and good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	0.008	lb/MMBtu	3 Hour			Good combustion practices and clean burning fuels (natural gas)
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	0.0068	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated	0.0415	lb/MMBtu	Low sulfur fuels and good combustion practices
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	0.0077	lb/MMBtu ($PM_{10,2.5}$)	1 Hour	0.019	lb/MMBtu ($PM_{10,2.5}$)	Good combustion controls
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.044 0.0044	lb/MMBtu (PM_{10}) lb/MMBtu ($PM_{2.5}$)	Not indicated	0.0168	lb/MMBtu ($PM_{10,2.5}$)	Good combustion
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	0.006	lb/MMBtu ($PM_{10,2.5}$)	Not indicated			Good combustion controls and low sulfur fuel
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	0.006	lb/MMBtu ($PM_{10,2.5}$)	Not indicated			Good combustion practices and pipeline quality natural gas
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	0.0073	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated			Pipeline quality natural gas
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	0.0036	lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated			Natural gas or a natural gas and ethane mixture only
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	0.0025 0.0066	lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated			Good combustion practices and the use of pipeline quality natural gas, combustion inlet air filter.

Table D-1.4 Summary of PM BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted PM Limit	Units	Averaging Period	Fuel Oil PM Limit	Units	Control
PA-0316	Renovo Energy Center, LLC	Two 1-on-1 Combustion Turbine	1/26/2018	500	MW	0.0043	lb/MMBtu	Not indicated			None indicated
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	0.00735	lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated			Good combustion practices and pipeline quality natural gas
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	0.0069	lb/MMBtu ($PM_{10,2.5}$)	N/A (stack test)			Good combustion practices and use of pipeline natural gas (<0.4 gr S/100scf)
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	0.0065	lb/MMBtu ($PM_{10,2.5}$)	N/A (stack test)			Good combustion practices and use of pipeline natural gas (<0.4 gr S/100scf)
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	0.0037 0.0069	lb/MMBtu (PM_{filt}) lb/MMBtu (PM_{10})	3 Hour	0.0167 0.0320	lb/MMBtu (PM_{filt}) lb/MMBtu (PM_{10})	Good combustion practice
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	0.008	lb/MMBtu ($PM_{2.5}$)	Not indicated			Air filter, use of natural gas, good combustion practices
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	0.0026 0.0042	lb/MMBtu (PM) lb/MMBtu ($PM_{10,2.5}$)	3 Hour			Good combustion practice
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	0.0052	lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated			Good combustion practices and use of pipeline natural gas (<0.4 gr S/100scf)
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	0.0034 0.006	lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Hourly max			Low sulfur fuel and good combustion practices
AL-0328	Alabama Power Compamy Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	0.004	lb/MMBtu ($PM_{10,2.5}$)	3 Hour			None indicated
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	0.0037	lb/MMBtu ($PM_{2.5}$)	Not indicated			Good combustion practices and use of low-sulfur fuels
PA-0334	Renovo Energy Center LLC/Renovo Plt	Two 1-on-1 Combined cycle combustion turbine	4/29/2021	3,940	MMBtu/hr	0.005	lb/MMBtu (w/ DB)	Not indicated	0.0122	lb/MMBtu	SCR, catalytic oxidizer
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW	0.006	lb/MMBtu ($PM,PM_{10,2.5}$)	N/A (stack test)			Good combustion practice and clean fuel
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	0.008	lb/MMBtu	N/A (stack test)			Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices.
AK-0088	Alaska LNG Liquefaction Facility	Four Combined-Cycle Combustion Turbines	7/7/2022	384	MMBtu/hr	0.007	lb/MMBtu ($PM,PM_{10,2.5}$)	3 Hour			Good combustion practices and burning clean fuel (natural gas)
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	0.0031 0.0041	lb/MMBtu (PM) lb/MMBtu ($PM_{10,2.5}$)	3 Hour			Good combustion practice
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	0.0049	lb/MMBtu	N/A			Good combustion practice

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

0.005384615

Table D-1.5 Summary of H2SO4 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted H_2SO_4 Limit	Units	Averaging Period	Fuel Oil H_2SO_4 Limit	Units	Control
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	2.11	lb/hr	Not indicated	2.31	lb/hr	Use of inherently low sulfur fuel
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.0005	lb/MMBtu	Not indicated	0.0005	lb/MMBtu	Low sulfur content fuel
FL-0354	Lauderdale Plant	Five GE 7F.05 Gas-Fired Turbines	8/25/2015	200	MW (each)	2	gr S/100 scf fuel	N/A (recordkeeping)	0.0015	wt% S in fuel	Use of clean (low sulfur) fuels
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	2	gr S/100 scf fuel	N/A (recordkeeping)	0.0015	wt% S in fuel	Use of clean (low sulfur) fuels
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	2	gr S/100 scf fuel	N/A (recordkeeping)			Use of clean (low sulfur) fuels
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	0.0032	lb/MMBtu	N/A (stack test)			None indicated
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2.3	lb/hr	3 Hour	4	lb/hr	Controls not feasible for NG. Use of ultra-low sulfur diesel only.
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	2	lb/MMBtu	3 Hour			Good combustion practice, low-sulfur fuel (<0.5 gr/100 scf)
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	0.0004	lb/MMBtu	Not indicated			Use of pipeline-quality natural gas
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	0.0005	lb/MMBtu	Not indicated			Use of low sulfur fuel
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	0.062	gr S/100 scf fuel	N/A (recordkeeping)			Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices.
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	0.001	lb/MMBtu	1-hr Average			None indicated
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	2.5	lb/hr	3 Hour			Exclusive use of pipeline quality natural gas
MD-0042	Wildcat Point Generation Facility	Two Combined-Cycle Gas-Fired Turbines	4/8/2014	1,000	MW (total)	9.7	lb/hr	3 Hour			Exclusive use of pipeline-quality natural gas
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	4.6	lb/hr	3 Hour			Initial and annual performance test using EPA Method 8 or equivalent
MD-0046	Keys Energy Center	Two Siemens SGT6-500FEE Combined-Cycle Gas-Fired Turbines	10/31/2014	235	MW (each)	4.6	lb/hr	N/A (stack test)			Good combustion practices and the use of pipeline quality natural gas
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1	lb/hr	Hourly max			Use of clean fuel (natural gas) with a fuel sulfur limit of 0.8 gr S/100scf
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	2.7	lb/hr	Hourly max			Good combustion practices and the use of pipeline quality natural gas
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	0.0013	lb/MMBtu	Hourly max			Good combustion practices and the use of pipeline quality natural gas
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	0.0013	lb/MMbtu	Hourly max			Use of clean fuel (natural gas) with a fuel sulfur limit of 1 gr S/100scf
NJ-0081	PSEG Fossil LLC Sewaren Station	Two Combustion Turbines	3/7/2014	625	MW (each)	2.74	lb/hr	Not indicated			Use of natural gas as a low sulfur fuel
NJ-0082	West Deptford Energy Station	One Combined-Cycle Combustion Turbine	7/18/2014	427	MW	0.74	lb/hr	Not indicated			Use of natural gas as a clean burning fuel
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	3.61	lb/hr	N/A (stack test)	4.27	lb/hr (stack test)	Use of natural gas as a clean burning fuel

Table D-1.5 Summary of H2SO4 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted H_2SO_4 Limit	Units	Averaging Period	Fuel Oil H_2SO_4 Limit	Units	Control
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	3.45	lb/hr	N/A (stack test)	4.8	lb/hr (stack test)	Use of natural gas as a clean burning fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	6.50E-04	lb/MMBtu	1 Hour			Use of natural gas with a fuel sulfur limit of 0.4 gr S/100scf
OH-0363	NTE Ohio, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	11/5/2014	3278.5	MMBTu/hr	0.0011	lb/MMBtu	Not indicated			Use of natural gas
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	2	tpy	12-mo Rolling			Good combustion practice. Use of natural gas with maximum sulfur content of 0.25 gr/100 scf
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	0.0011	lb/MMBtu	Not indicated			Low sulfur fuel
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	0.0017	lb/MMBtu	1 Hour	0.0019	lb/MMBtu (1-hr)	Low sulfur fuels
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	0.0011	lb/MMBtu	Not indicated			Low sulfur fuel
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	0.0011	lb/MMBtu	Not indicated			Low sulfur fuel
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	0.0011	lb/MMBtu	Not indicated			Pipeline quality natural gas with sulfur limit of 0.5 gr/100 scf
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	0.0011	lb/MMBtu	Not indicated			Natural gas or a natural gas and ethane mixture only
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	0.00102	lb/MMBtu	Not indicated			Good combustion practices and pipeline quality natural gas
PA-0298	Good Springs NGCC Facility	Siemens 5000 Combined-Cycle Turbine	3/4/2014	346	MW	3.4	lb/hr (w/ DB)	Not indicated			None indicated
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	0.0006	lb/MMBtu (w/ DB)	Not indicated			Low sulfur fuel and good combustion practice
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	0.0011	lb/MMBtu (w/ DB)	Not indicated			None indicated
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	0.0009	lb/MMBtu	Not indicated			Exclusive natural gas
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	0.0014	lb/MMBtu	Not indicated	0.0013	lb/MMBtu	Low sulfur fuels and good combustion practices (NG). Water/steam injection (ULSD).
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	0.0009	lb/MMBtu	Not indicated			None indicated
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	5.98	tpy	Not indicated			None indicated
PA-0334	Renovo Energy Center LLC/Renovo Plt	Two 1-on-1 Combined cycle combustion turbine	4/29/2021	3,940	MMBtu/hr	0.0009	lbMMBtu (w/ DB)	Not indicated	0.0012	lb/MMBtu	SCR, catalytic oxidizer
TX-0714	Sr. Berton Electric Generating Station	Two 1-on-1 Gas Fired Combustion Turbines	12/19/2014	240	MW	0.5	gr S/100 scf fuel	N/A (recordkeeping)			Natural gas as fuel
TX-0730	Colorado Bend Energy Center	Two 1-on-1 Combustion Turbine	4/1/2015	1,100	MW	2 0.5	gr S/100 scf fuel	1-Hour Annual			Efficient combustion, natural gas fuel
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	10.4	tpy	Not indicated			Low sulfur fuel
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	1 0.25	gr S/100 scf fuel	1-Hour Annual			Good combustion practices, low sulfur fuel
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	1 0.25	gr S/100 scf fuel	1-Hour Annual			Good combustion practices, low sulfur fuel
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	5 1	gr S/100 scf fuel	1-Hour Annual			Good combustion practices, low sulfur fuel
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	1	gr S/100 scf fuel	Not indicated			Pipeline quality natural gas

Table D-1.5 Summary of H2SO4 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted H_2SO_4 Limit	Units	Averaging Period	Fuel Oil H_2SO_4 Limit	Units	Control
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.00053	lb/MMBtu	Not indicated			Low sulfur fuel
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	2.5	lb/hr	3 Hours			Use of pipeline natural gas (<0.4 gr S/100scf)
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	2.2	lb/hr	3 Hours			Use of pipeline natural gas (<0.4 gr S/100scf)
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	0.0012	lb/MMBtu	3 Hours			Use of pipeline natural gas (<0.4 gr S/100scf)
WI-0300	Nemadji Trail Energy Center	One 1-on-1 Combined Cycle Combustion Turbine	9/1/2020	4,671	MMBTU/hr	7.8	lb/hr	Not indicated	7	lb/hr	Use of pipeline quality natural gas and ULSD (<15ppm)
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	0.0009	lb/MMBtu	Not indicated			Use of natural gas
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	0.0008	lb/MMBtu	Not indicated			Use of natural gas
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW (total)	0.4	gr S/100 scf fuel	N/A (recordkeeping)			Low sulfur fuel

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

Table D-1.6 CO_2 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO_2 Limit	Units	Averaging Period	Fuel Oil CO_2 Limit	Units	Control
AK-0088	Alaska LNG Liquefaction Facility	Six Simple Cycle Gas-Fired Turbines	7/7/2022	1,113	MMBtu/hr (each)	117.1	lb/MMBtu	3-Hours			Good combustion practices and burning clean fuels (natural gas)
AK-0088	Alaska LNG Liquefaction Facility	Four Combined-Cycle Combustion Turbines	7/7/2022	384	MMBtu/hr	117.1	lb/MMBtu	3-Hours			Good combustion practices and burning clean fuels (natural gas)
AL-0328	Alabama Power Compamy Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	1000	lb/MWh	Not indicated			Efficient design
AL-0329	Colbert Combustion Turbine Plant	Three Simple Cycle Gas-Fired Turbines	9/21/2021	229	MW (each)	120	lb/MMBtu	Not indicated			None indicated
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	809	lb/MWh	12-mo Rolling			None indicated
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	816	lb/MWh-net	12-mo Rolling			Use of low carbon fuel
FL-0354	Lauderdale Plant	Five GE 7F.05 Gas-Fired Turbines	8/25/2015	200	MW (each)	1372	lb/MWh	12- or 36-month rolling	1871	lb/MWh	Use of natural gas with ULSD as backup fuel
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	850	lb/MWh (CO_2e)	12-mo Rolling	1210	lb/MWh (CO_2e)	Use of low-emitting fuels and technologies. ULSD limited to 500 hr/yr.
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	875	lb/MWh	12-mo Rolling			Low-emitting fuel
IA-0107	Marshalltown Generating Station	1-on-1 GE F-class Combned-Cycle Gas-Fired Turbine	4/14/2014	600	MW	951	lb/MWh	12-mo Rolling			None indicated
IL-0121	Invenergy Nelson Expansion	Two Simple-Cycle Gas-Fired Turbines	9/27/2016	190	MW (each)	1367	lb/MWhr-gross	12-mo Rolling	1934	lb/MWh-gross	Turbine-generator design and proper operation
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	4,026,300	tpy	12-mo Rolling			Equipment design and proper operation
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	1000	lb/MWh-gross	12-mo Rolling			Equipment design and proper operation
IL-0133	Lincoln Land Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/29/2022	3,647	MMBtu/hr	850	lb/MWh-gross	12-mo Rolling			Inherently lower-polluting design, good combustion practices and operational energy efficiency
IN-0365	Maple Creek Energy LLC	One 1-on-1 Combined-Cycle Gas-Fired Turbine	6/19/2023	3,800-4,200	MMBtu/hr	726	lb/MWh-gross	12-mo Rolling			None indicated
LA-0327	Washington Parish Energy Center	Two Simple-Cycle Gas-Fired Turbines	5/23/2018	2,201	MMBtu/hr (each)	50	kg/GJ	Ann. Average			Facility-wide energy efficiency measures (such as good combustion), and use of pipeline quality natural gas
LA-0331	Calcasieu Pass LNG	Three Simple Cycle Gas-Fired Turbines	9/21/2018	927	MMBtu/hr (each)	1,426,146	tpy	Ann. Total			Exclusively combust low carbon fuel gas, good combustion practices, good operation and maintenance practices, and insulation
LA-0331	Calcasieu Pass LNG	5-on-2 Combined-Cycle Gas-Fired Turbines	9/21/2018	710	MW (total)	2,602,275	tpy	Ann. Total			Combust low carbon fuel gas and good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	1000	lb/MWh	Not indicated			Thermally efficient combustion turbines and good combustion practices
LA-0364	FG LA Complex	2 Combined-Cycle Gas-Fired Turbines	1/6/2020	2,222	MMBtu/hr	1,096,666	tpy	Not indicated			Use of natural gas as fuel, energy-efficient design options, and operational/maintenance practices.

Table D-1.6 CO_2 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO_2 Limit	Units	Averaging Period	Fuel Oil CO_2 Limit	Units	Control
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	875	lb/MWh	Ann. Average			Use of gaseous fuel (pipeline-quality natural gas), thermally efficient turbines, and good combustion practices.
MA-0039	Salem Harbor Station	Two 1-on-1 GE 7F.5 Combined-Cycle Gas-Fired Turbines	1/30/2014	315	MW (each)	825	lb/MWh	365-day Rolling			None indicated
MD-0041	CPV St. Charles	Two 1-on-1 GE F-Class Combined-Cycle Gas-Fired Turbines	4/23/2014	725	MW (total)	878	lb/MWh	12-mo Rolling			None indicated
MD-0042	Wildcat Point Generation Facility	Two Combined-Cycle Gas-Fired Turbines	4/8/2014	1,000	MW (total)	3,498,026	tpy	Ann. Total			None indicated
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	865	lb/MWh	12-mo Rolling			None indicated
MD-0046	Keys Energy Center	Two Siemens SGT6-500FEE Combined-Cycle Gas-Fired Turbines	10/31/2014	235	MW (each)	869	lb/MWh	12-mo Rolling			CO2 CEMS
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	802	lb/MWh	Not indicated			Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	992,286	tpy	12-mo Rolling			Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1,425,081	tpy	12-mo Rolling			
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	806	lb/MWh	12-mo Rolling			Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	794	lb/MWh	12-mo Rolling			Energy efficiency measures
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2,793,722	tpy	12-mo Rolling			Energy efficiency measures
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	1,000	lb/MWh	12-mo Rolling			Low carbon fuel, good combustion practices, energy efficiency measures
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	888	lb/MWh-gross	12-mo Rolling			Use of natural gas as a clean burning fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	7,604	BTU/kWh	Not indicated			Good combustion practices and use of natural gas
OH-0363	NTE Ohio, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	11/5/2014	3278.5	MMBTu/hr	888	lb/MWh-gross	12-mo Rolling			Good combustion, oxidation catalysts, use of natural gas, energy efficiency
OH-0365	Rolling Hills Generating, LLC	Four Combined-Cycle Combustion Turbines	5/20/2015	200	MW	7,471	BTU/kWh	Not indicated			High efficiency
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	833	lb/MWh	Not indicated			High efficient combustion technology
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	481,301	lb/hr	Hourly max	546,182	lb/hr	High efficient combustion technology
OH-0370	Trumbull Energy Center	One 1-on-1 Combined-Cycle Gas Turbine	9/7/2017	940	MW	833	lb/MWh	Not indicated			High efficient combustion technology
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	833	lb/MWh	Not indicated			High efficiency combustion design
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	846	lb/MWh	12-mo Rolling			High efficiency combustion practices as recommended by the manufacturer

Table D-1.6 CO_2 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO_2 Limit	Units	Averaging Period	Fuel Oil CO_2 Limit	Units	Control
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	775	lb/MWh	12-mo Rolling			High efficiency combustion practices as recommended by the manufacturer
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	1000	lb/MWh	12-mo Rolling			High efficiency combustion technology
OR-0050	Troutdale Energy Center	GE LMS100 Simple-Cycle Gas-Fired Turbines	3/5/2014	1,690	MMBtu/hr (each)	1,707	lb/MWh-gross	365-day Rolling			Thermal efficiency and clean fuels
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	1,881,905	tpy	Not indicated			Good combustion practices
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	1,629,115	tpy	Not indicated			None indicated
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	879	lb/MWh-gross	Not indicated			None indicated
TN-0162	TVA Johnsonville Cogeneration	One 1-on-1 Gas Fired Combustion Turbine	4/19/2016	1,339	MMBtu/hr	1,800	lb/MWh	12-mo Rolling			Good combustion design and practices
TX-0730	Colorado Bend Energy Center	Two 1-on-1 Combustion Turbine	4/1/2015	1,100	MW	879	lb/MWh-gross	Not indicated			Efficient processes, practices, and design
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	886	lb/MWh	Not indicated			Low carbon fuel, good combustion practices, efficient combined cycle design
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	1,341	lb/MWh	Not indicated			Good combustion practices
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	924	lb/MWh	Not indicated			Good combustion practices
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	504,514	tpy				Good combustion practices and use of low carbon fuel
TX-0794	Hill County Generating Station	Simple Cycle Gas-Fired Turbines	4/7/2016	171	MW (each)	1,434	lb/MWh	Not indicated	1,434	lb/MWh	None indicated
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	960	lb/MWh	Not indicated			Pipeline quality natural gas
TX-0826	Mustang Station	Simple Cycle Gas-Fired Turbines	8/16/2017	162.8	MW	120	lb/MMBtu	Not indicated			Pipeline quality natural gas and good combustion practices
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	884	lb/MWh	Not indicated			Pipeline quality natural gas and good combustion practices
TX-0975	Freestone Peakers Plant	One GE 7FA.05 Simple-Cycle Gas-Fired Turbine	6/13/2024	221	MW	800	lb/MWh	Not indicated			Good combustion practices
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	890	lb/MWh	30-Years			None indicated
VA-0328	C4GT, LLC	One 2-on-1 GE 7HA.02 Combined-Cycle Turbines	4/26/2018	3,482	MMBtu/hr	883	lb/MWh	12-mo Rolling			Energy efficient combustion practices and low GHG fuels
VA-0328	C4GT, LLC	One 2-on-1 Siemens SGT6-8000H Combined-Cycle Turbines	4/26/2018	3,116	MMBtu/hr	883	lb/MWh	12-mo Rolling			Energy efficient combustion practices and low GHG fuels
VA-0332	Chickahominy Power, LLC	Three 1-on-1 Natural Gas-Fired Combined Cycle Configuration	6/24/2019	310	MW (each)	812	lb/MWh	12-mo Rolling			Energy efficient combustion practices and low GHG fuels
WI-0300	Nemadji Trail Energy Center	One 1-on-1 Combined Cycle Combustion Turbine	9/1/2020	4,671	MMBTU/hr	850	lb/MWh	12-mo Rolling	1,180	lb/MWh	Efficient turbine design, pipeline quality natural gas and diesel, oxidation catalyst
WV-0025	Moundsville Combined Cycle Power Plant	Two GE 7FA.04 Combined Cycle Combustion Turbines	11/21/2014	197	MW (each)	792	lb/MWh	Not indicated			Use of GE Frame 7EA CT and low carbon fuel
WV-0028	Waverly Power Plant	Two GE 7FA.004 Simple-Cycle Gas-Fired Turbines	3/13/2018	167.8	MW (each)	1,300	lb/MWh	12-mo Rolling			Use of natural gas and GE 7FA.004

Table D-1.6 CO_2 BACT Determination for CCGT

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted CO_2 Limit	Units	Averaging Period	Fuel Oil CO_2 Limit	Units	Control
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	826	lb/MWh	Not indicated			Use of natural gas and GE7HA
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	829	lb/MWh	Not indicated			Use of natural gas and GE7HA
WV-0033	Maidsville	Two 2-on-1 Combined Cycle Combustion Turbines	1/5/2022	1275	MW	852	lb/MWh	12-mo Rolling			Thermal efficiency/combustion air cooling and use of lower carbon fuels

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

Table D-2.1 Summary of NOx BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Nitrogen Oxides (NOx)	8307	MMBTU/H	0.05	LB/MMBTU	12-MONTH ROLLING	Selective Catalytic Reduction
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Nitrogen Oxides (NOx)	7624	MMBTU/H	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	Staged combustion, low-NOx burners, overfire air, and SCR.
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Nitrogen Oxides (NOx)	6670	MMBTU/H	0.06	LB/MMBTU	ROLLING 30 DAY AVG	low-NOx burners with OFA, Selective Catalytic Reduction
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	LMS Units 1 and 2	2/1/2010	Nitrogen Oxides (NOx)	9061	MMBtu/H	0.25	LB/MMBTU	30-DAY	Tuning of existing low-NOx firing system to induce deeper state combustion.
TX-0556	HARRINGTON STATION UNIT 1 BOILER	Unit 1 Boiler	1/15/2010	Nitrogen Oxides (NOx)	3630	MMBTU/H	1452	LB/H		Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Nitrogen Oxides (NOx)	8190	MMBTU/H	0.05	LB/MMBTU	30-DAY ROLLING	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	BOILER (2), PULVERIZED COAL FIRED	10/8/2009	Nitrogen Oxides (NOx)	5191	MMBTU/H	519	LB/H	AS A 24-HOUR AVERAGE EACH BOILER	SELECTIVE CATALYTIC REDUCTION
NE-0049	OPPD NEBRASKA CITY STATION	NCS UNIT 1	2/26/2009	Nitrogen Oxides (NOx)	370	T/YR	0.23	LB/MMBTU	30-DAY ROLLING AV	LNB W/OVERFIRE AIR PORT SYSTEM
AR-0094	JOHN W. TURK JR. POWER PLANT	PC BOILER	11/5/2008	Nitrogen Oxides (NOx)	6000	MMBTU/H	0.067	LB/MMBTU	24 HOUR ROLLING	SELECTIVE CATALYTIC REDUCTION (SCR)
MO-0077	NORBORNE POWER PLANT	MAIN BOILER	2/22/2008	Nitrogen Oxides (NOx)	3762420	T/YR	0.065	LB/MMBTU	30 DAYS ROLLING AVERAGE	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR
WY-0064	DRY FORK STATION	PC BOILER (ES1-01)	10/15/2007	Nitrogen Oxides (NOx)			0.05	LB/MMBTU	12 MONTH ROLLING	LOW NOX BURNERS AND SCR
OK-0118	HUGO GENERATING STA	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	2/9/2007	Nitrogen Oxides (NOx)			0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)
WY-0063	WYGEN 3	PC BOILER	2/5/2007	Nitrogen Oxides (NOx)			0.05	LB/MMBTU	12 MONTH ROLLING	SCR/LNB/OVERFIRE AIR
TX-0499	SANDY CREEK ENERGY STATION	PULVERIZED CAOL BOILER	7/24/2006	Nitrogen Oxides (NOx)			1637	LB/H	1-HR	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.

Table D-2.1 Summary of NOx BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 2	1/27/2006	Nitrogen Oxides (NOx)			0.08	LB/MMBTU	30 DAYS ROLLING AVERAGE	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 1	1/27/2006	Nitrogen Oxides (NOx)			0.1	LB/MMBTU	30 DAYS ROLLING AVERAGE	

Table D-2.2 Summary of CO BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0145	INDEPENDENCE PLANT	UNIT 1 COAL FIRED BOILER	5/16/2017	Carbon Monoxide	525	TONS/HR	0.15	LB/MMBTU	3-HR	Good Combustion
AR-0145	INDEPENDENCE PLANT	UNIT 2 COAL FIRED BOILER	5/16/2017	Carbon Monoxide	525	TONS/HR	0.15	LB/MMBTU	3-HR	Good Combustion
AR-0141	PLUM POINT ENERGY STATION	BOILER, SN-01 UNIT 1	10/26/2016	Carbon Monoxide	6684	MMBTU/H	0.15	LB/MMBTU		GOOD COMBUSTION PRACTICE
AR-0126	WHITE BLUFF PLANT	Unit 2 Coal-Fired Boiler	9/25/2015	Carbon Monoxide	8700	MMBTU/H	1342.5	LB/H		
AR-0126	WHITE BLUFF PLANT	Unit 1 Coal-Fired Boiler	9/25/2015	Carbon Monoxide	8700	MMBTU/H	1342.5	LB/H		
NE-0056	OPPD - NEBRASKA CITY STATION	UNIT 2 BOILER	7/3/2014	Carbon Monoxide	0		0.13	LB/MMBTU	30 DAY ROLLING AVERAGE	
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	(2) coal-fired boilers	12/20/2013	Carbon Monoxide	900	MW	0.33	LB/MMBTU	24-HR ROLLING AVERAGE	good combustion practices
MI-0408	PRESQUE ISLE POWER PLANT	Boiler 7 (EUBOILER7)	12/9/2013	Carbon Monoxide	1010	MMBTU/H heat input	0.2	LB/MMBTU	30 OPERATING DAY ROLLING AVGERAGE	Efficient combustion practices, add emission limit, CEMS for monitoring.
MI-0408	PRESQUE ISLE POWER PLANT	Boilers 5 and 6 (FG5&6)	12/9/2013	Carbon Monoxide	995	MMBTU/H heat input each boiler.	0.2	LB/MMBTU	30 OPERATING DAY ROLLING AVERAGE	Efficient combustion practices, add emission limit, CEMS for monitoring.
MI-0408	PRESQUE ISLE POWER PLANT	Boilers 8 & 9 (FG8&9)	12/9/2013	Carbon Monoxide	1010	MMBTU/H heat input	0.2	LB/MMBTU	30 OPERATING DAY ROLLING AVERAGE	Efficient combustion practices, add emission limit, CEMS for monitoring.
NE-0052	WHELAN ENERGY CENTER	UNIT 1	8/10/2012	Carbon Monoxide	835	MMBTU/H	0.5	LB/MMBTU	30 DAYS	GOOD COMBUSTION PRACTICES
NE-0051	PLATTE GENERATING STATION	COAL FIRED BOILER	8/9/2012	Carbon Monoxide	1048	MMBTU/H	0.5	LB/MMBTU	30 DAY ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
MO-0087	KANSAS CITY POWER & LIGHT - MONTROSE GENERATING STATION	Unit 1	4/9/2012	Carbon Monoxide	0		0.25	LB/MMBTU	30 DAY ROLLING	good combustion
MO-0087	KANSAS CITY POWER & LIGHT - MONTROSE GENERATING STATION	Unit 2	4/9/2012	Carbon Monoxide	0		0.25	LB/MMBTU	30 DAY ROLLING	good combustion
MO-0087	KANSAS CITY POWER & LIGHT - MONTROSE GENERATING STATION	Unit 3	4/9/2012	Carbon Monoxide	0		0.25	LB/MMBTU	30 DAY ROLLING	good combustion
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	Boiler	10/28/2011	Carbon Monoxide	5060	MMBtu/h	0.12	LB/MMBTU	30-DAY ROLLING AVERAGE	Good combustion practices
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Carbon Monoxide	8307	MMBTU/H	0.1	LB/MMBTU	30-DAY ROLLING	Good combustion practices
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Carbon Monoxide	7624	MMBTU/H	0.15	LB/MMBTU	EACH, 30D ROLL. AVG. EXCL. STRTUP&SHTD WN	Good combustion practices.
MO-0078	THOMAS HILL ENGERGY CENTER	Unit 1 Cyclone Boiler	12/17/2010	Carbon Monoxide	2180	MMBTU/H	0.55	LB/MMBTU	30-DAY ROLLING AVERAGE	Good combustion practices
MO-0078	THOMAS HILL ENGERGY CENTER	Unit 2 Cyclone Boiler	12/17/2010	Carbon Monoxide	3579	MMBTU/H	0.55	LB/MMBTU	30-DAY ROLLING AVERAGE	Good Combustion practices

Table D-2.2 Summary of CO BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MO-0084	NEW MADRID POWER PLANT	UNIT 1 CYCLONE BOILER	12/17/2010	Carbon Monoxide	7150	MMBTU/H	0.55	LB/MMBTU	30-DAY ROLLING AVG	GOOD COMBUSTION PRACTICES
MO-0084	NEW MADRID POWER PLANT	UNIT 2 CYCLONE BOILER	12/17/2010	Carbon Monoxide	7150	MMBTU/H	0.55	LB/MMBTU	30-DAY ROLLING AVG	GOOD COMBUSTION PRACTICES
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Carbon Monoxide	6670	MMBTU/H	0.12	LB/MMBTU	30-DAY ROLLING	Good combustion practices
MN-0081	BOSWELL ENERGY CENTER	Boiler 4	4/28/2010	Carbon Monoxide	600	MMBTU/H	0.15	LB/MMBTU	30 D ROLL EXCEPT STARTUP/SHUT DOWN	CO monitored by CEMS.
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	LMS Units 1 and 2	2/1/2010	Carbon Monoxide	9061	MMBtu/H	0.33	LB/MMBTU		Good combustion controls.
TX-0556	HARRINGTON STATION UNIT 1 BOILER	Unit 1 Boiler	1/15/2010	Carbon Monoxide	3630	MMBTU/H	0.33	LB/MMBTU	30-DAY	Good combustion practices.
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Carbon Monoxide	8190	MMBTU/H	0.125	LB/MMBTU	24-HOUR ROLLING	EFFICIENT COMBUSTION
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	BOILER (2), PULVERIZED COAL FIRED	10/8/2009	Carbon Monoxide	5191	MMBTU/H	779	LB/H	AS A 3-HOUR AVERAGE EACH BOILER	GOOD COMBUSTION PRACTICES
WY-0068	WYODAK PLANT	UNIT 1	5/20/2009	Carbon Monoxide	4700	MMBTU/H	0.25	LB/MMBTU	30-DAY ROLLING	GOOD COMBUSTION CONTROLS
WY-0069	NAUGHTON PLANT	UNIT 1	5/20/2009	Carbon Monoxide	1850	MMBTU/H	0.25	LB/MMBTU	30-DAY ROLLING AVERAGE	COMBUSTION CONTROLS
WY-0069	NAUGHTON PLANT	UNIT 2	5/20/2009	Carbon Monoxide	2400	MMBTU/H	0.25	LB/MMBTU	30 DAY ROLLING	COMBUSTION CONTROLS
WY-0069	NAUGHTON PLANT	UNIT 3	5/20/2009	Carbon Monoxide	3700	MMBTU/H	0.02	LB/MMBTU		COMBUSTION CONTROLS
NE-0049	OPPD NEBRASKA CITY STATION	NCS UNIT 1	2/26/2009	Carbon Monoxide	370	T/YR	0.5	LB/MMBTU	30-DAY ROLLING AV	GOOD COMBUSTION PRACTICES
AZ-0050	CORONADO GENERATING STATION	UNIT 2	1/22/2009	Carbon Monoxide	4719	MMBTU	0.5	LB/MMBTU	30-DAY AVERAGE	GOOD COMBUSTION PRACTICES
AR-0094	JOHN W. TURK JR. POWER PLANT	PC BOILER	11/5/2008	Carbon Monoxide	6000	MMBTU/H	0.15	LB/MMBTU	30 DAY ROLLING AVERAGE	GOOD COMBUSTION
WY-0065	DAVE JOHNSTON	UNIT 4	6/27/2008	Carbon Monoxide	1734370	T/YR	0.2	LB/MMBTU	30-DAY ROLLING	
MO-0077	NORBORNE POWER PLANT	MAIN BOILER	2/22/2008	Carbon Monoxide	3762420	T/YR	0.15	LB/MMBTU	30 DAYS ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
FL-0306	OUC CURTIS H. STANTON ENERGY CENTER	A 468 MEGAWATT (MW) FOSSIL FUEL FIRED STEAM ELECTRIC GENERATING UNIT (UNIT 1)	2/6/2008	Carbon Monoxide	4286	MMBTU/H	0.18	LB/MMBTU	30-OPERATING DAY ROLLING	CEMS SHALL MONITOR AND RECORD EMISSIONS
FL-0306	OUC CURTIS H. STANTON ENERGY CENTER	A 468 MEGAWATT (MW) FOSSIL FUEL FIRED STEAM ELECTRIC GENERATING UNIT (UNIT 2).	2/6/2008	Carbon Monoxide	4286	MMBTU/H	0.15	MMBTU/H	30-OPERATING DAY ROLLING	CEMS SHALL MONITOR AND RECORD EMISSIONS
WY-0064	DRY FORK STATION	PC BOILER (ES1-01)	10/15/2007	Carbon Monoxide			0.15	LB/MMBTU	ANNUAL	GOOD COMBUSTION PRACTICES

Table D-2.2 Summary of CO BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IA-0090	GEORGE NEAL NORTH	NEAL 2 BOILER	9/5/2007	Carbon Monoxide			1.63	LB/MMBTU	THREE (3) HOUR ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
MD-0038	BRANDON SHORES GENERATING STATION	BRANDON SHORES UNIT 1 & UNIT 2	6/2/2007	Carbon Monoxide			0.2	LB/MMBTU	3-HOUR AVERAGE	GOOD COMBUSTION PRACTICES
FL-0295	CRYSTAL RIVER POWER PLANT	FFFSG UNITS 4 AND 5	5/18/2007	Carbon Monoxide			0.17	LB/MMBTU	30-DAY ROLLING CEMS AVG	COMBUSTION CONTROL AND OPERATION
CO-0072	CRAIG ELECTRIC GENERATING STATION	Unit 3 Coal boiler	5/16/2007	Carbon Monoxide			0.215	LB/MMBTU	30-DAY ROLLING AVE	Good Combustion Practices
FL-0307	TAMPA ELECTRIC COMPANY (TEC) UNIT 4	DRY-BOTTOM TANGENTIALLY FIRED UTILITY BOILER	5/1/2007	Carbon Monoxide			0.2	LB/MMBTU	30-BOILER OPERATING DAY ROLLING AVERAGE	LNB AND SOFA SYSTEMS: THE PERMITTEE SHALL ADHERE TO GOOD COMBUSTION PRACTICES (GCP) TO ACHIEVE THE BACT CO EMISSIONS LIMITS SET BY THIS PERMIT.
IA-0091	OTTUMWA GENERATING STATION	BOILER #1	2/27/2007	Carbon Monoxide			0.163	LB/MMBTU	30-DAY ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
OK-0118	HUGO GENERATING STA	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	2/9/2007	Carbon Monoxide			0.15	LB/MMBTU	30 DAY ROLLING AVERAGE	GOOD COMBUSTION CONTROL
WY-0063	WYGEN 3	PC BOILER	2/5/2007	Carbon Monoxide			0.15	LB/MMBTU	3 X 1-HOUR TESTS	GOOD COMBUSTION
FL-0308	C.E. MCINTOSH, JR. POWER PLANT UNIT 3	364 MW DRY BOTTOM WALL-FIRED FOSSIL FUEL FIRED STEAM GENERATOR	12/29/2006	Carbon Monoxide			0.2	LB/MMBTU	30-DAY ROLLING AVERAGE	
LA-0210	DOLET HILLS POWER STATION	UNIT 1 BOILER	11/21/2006	Carbon Monoxide			1364	LB/H	MAXIMUM HOURLY	GOOD COMBUSTION PRACTICES
CO-0062	RAWHIDE ENERGY STATION	COAL-FIRED BOILER 101	9/27/2006	Carbon Monoxide			0.15	LB/MMBTU	ROLLING 8-H AVERAGE	GOOD COMBUSTION PRACTICES
MO-0083	NEW MADRID POWER PLANT	UNIT 1 CYCLONE BOILER	9/18/2006	Carbon Monoxide			0.55	LB/MMBTU	30 DAY ROLLING AVG	GOOD COMBUSTION PRACTICES.
NE-0045	GERALD GENTLEMAN STATION	UNIT #1 BOILER	8/18/2006	Carbon Monoxide			0.05	LB/MMBTU	30 DAY ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
IL-0107	DALLMAN POWER PLANT	DALLMAN 4 ELECTRICAL GENERATING UNIT	8/10/2006	Carbon Monoxide			0.12	LB/MMBTU	3-HOUR BLOCK AVERAGE	GOOD COMBUSTION PRACTICES.
TX-0499	SANDY CREEK ENERGY STATION	PULVERIZED CAOL BOILER	7/24/2006	Carbon Monoxide			2456	LB/H	1-HR	
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 2	1/27/2006	Carbon Monoxide			0.14	LB/MMBTU	30 DAYS ROLLING AVERAGE	
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 1	1/27/2006	Carbon Monoxide			0.16	LB/MMBTU	30 DAYS ROLLING AVERAGE	GOOD COMBUSTION CONTROL PRATICE
MI-0380	ST. CLAIR POWER PLANT	BOILERS NO. 1 AND NO. 2	1/4/2006	Carbon Monoxide			0		SEE NOTE	GOOD COMBUSTION PRACTICES

Table D-2.3 Summary of VOC BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Volatile Organic Compounds (VOC)	8307	MMBTU/H	0.0036	LB/MMBTU	12-MONTH ROLLING AVG	Good combustion practice
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Volatile Organic Compounds (VOC)	7624	MMBTU/H	0.0034	LB/MMBTU	EACH, TEST PROTOCOL	Good combustion practices.
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Volatile Organic Compounds (VOC)	6670	MMBTU/H	0.0034	LB/MMBTU	ANNUAL / STACK TEST	Good combustion practices
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Volatile Organic Compounds (VOC)	8190	MMBTU/H	0.003	LB/MMBTU	TEST METHOD	EFFICIENT COMBUSTION
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	BOILER (2), PULVERIZED COAL FIRED	10/8/2009	Volatile Organic Compounds (VOC)	5191	MMBTU/H	19.2	LB/H	AS A 3-HOUR AVERAGE EACH BOILER	GOOD COMBUSTION PRACTICES
AR-0094	JOHN W. TURK JR. POWER PLANT	PC BOILER	11/5/2008	Volatile Organic Compounds (VOC)	6000	MMBTU/H	0.0008	LB/MMBTU	3 HOUR AVERAGE	GOOD COMBUSTION
MO-0077	NORBORNE POWER PLANT	MAIN BOILER	2/22/2008	Volatile Organic Compounds (VOC)	3762420	T/YR	0.0036	LB/MMBTU	TEST METHOD AVERAGE	GOOD COMBUSTION PRACTICES
WY-0064	DRY FORK STATION	PC BOILER (ES1-01)	10/15/2007	Volatile Organic Compounds (VOC)			0.0037	LB/MMBTU	ANNUAL	GOOD COMBUSTION PRACTICES
MD-0038	BRANDON SHORES GENERATING STATION	BRANDON SHORES UNIT 1 & UNIT 2	6/2/2007	Volatile Organic Compounds (VOC)			0.0024	LB/MMBTU	3-HOUR AVERAGE	GOOD COMBUSTION PRACTICE
FL-0295	CRYSTAL RIVER POWER PLANT	FFFSG UNITS 4 AND 5	5/18/2007	Volatile Organic Compounds (VOC)			0.004	LB/MMBTU		COMBUSTION CONTROL AND OPERATION
OK-0118	HUGO GENERATING STA	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	2/9/2007	Volatile Organic Compounds (VOC)			0.0036	LB/MMBTU	ANNUAL	GOOD COMBUSTION CONTROLS
TX-0499	SANDY CREEK ENERGY STATION	PULVERIZED CAOL BOILER	7/24/2006	Volatile Organic Compounds (VOC)			29	LB/H		
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 2	1/27/2006	Volatile Organic Compounds (VOC)			0.0036	LB/MMBTU	30 DAYS ROLLING AVERAGE	
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 1	1/27/2006	Volatile Organic Compounds (VOC)			0.0036	LB/MMBTU		GOOD COMBUSTION CONTROL PRACTICE

Table D-2.4 Summary of Filterable PM BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	6/29/2011	Particulate matter, filterable (FPM)	3030	MMBTU/H EACH	0.01	LB/MMBTU	EACH; TEST PROTOCOL	Pulse jet fabric filter
MI-0403	HOLLAND BOARD OF PUBLIC WORKS-JAMES DEYOUNG PLANT	CFB boiler	2/11/2011	Particulate matter, filterable (FPM)	865	MMBTU/H	0.01	LB/MMBTU	TEST PROTOCOL	Fabric filter and fugitive dust control plan
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Particulate matter, filterable (FPM10)	8307	MMBTU/H	0.012	LB/MMBTU	12-MONTH ROLLING AVG	Fabric Filter
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Particulate matter, filterable (FPM)	7624	MMBTU/H	0.011	LB/MMBTU	EACH, TEST/ OR 24H ROLL.AVG. IF PM CEMS	ESPs and wet flue gas desulfurization.
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Particulate matter, filterable (FPM10)	6670	MMBTU/H	0.012	LB/MMBTU	ANNUAL / BASED ON STACK TEST	fabric filter
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Particulate matter, filterable (FPM)	8190	MMBTU/H	0.011	LB/MMBTU	TEST METHOD	FABRIC FILTER
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	BOILER (2), PULVERIZED COAL FIRED	10/8/2009	Particulate matter, filterable (FPM10)	5191	MMBTU/H	125	LB/H	AS 3-HR AVERAGE EACH BOILER	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)
AZ-0050	CORONADO GENERATING STATION	UNIT 2	1/22/2009	Particulate matter, filterable (FPM10)	4719	MMBTU	0.03	LB/MMBTU	3-HOUR AVG	ESP
AR-0094	JOHN W. TURK JR. POWER PLANT	PC BOILER	11/5/2008	Particulate matter, filterable (FPM10)	6000	MMBTU/H	0.012	LB/MMBTU	3 HOUR AVERAGE	FABRIC FILTER
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	2 CIRCULATING FLUIDIZED BED BOILERS	6/30/2008	Particulate matter, filterable (FPM)	3132	MMBTU/H	0.01	LB/MMBTU	3 HOURS	GOOD COMBUSTIONS PRACTICES AND BAGHOUSE
MO-0077	NORBORNE POWER PLANT	MAIN BOILER	2/22/2008	Particulate matter, filterable (FPM10)	3762420	T/YR	0.018	LB/MMBTU	3 HOURS ROLLING AVERAGE (TOTAL PAM10)	FABRIC FILTRATION SYSTEM (BAGHOUSE)
WY-0064	DRY FORK STATION	PC BOILER (ES1-01)	10/15/2007	Particulate matter, filterable (FPM10)			0.012	LB/MMBTU	ANNUAL	FABRIC FILTER (BAGHOUSE)
FL-0295	CRYSTAL RIVER POWER PLANT	FFFSG UNITS 4 AND 5	5/18/2007	Particulate matter, filterable (FPM10)			0.03	LB/MMBTU		MODIFIED ESP (IMPROVEMENTS)
CO-0072	CRAIG ELECTRIC GENERATING STATION	Unit 3 Coal boiler	5/16/2007	Particulate matter, filterable (FPM10)			0.012	LB/MMBTU	AVE OVER STACK TEST LENGTH	Baghouse
CO-0072	CRAIG ELECTRIC GENERATING STATION	Unit 3 Coal boiler	5/16/2007	Particulate matter, filterable (FPM)			0.013	LB/MMBTU	AVE OVER STACK TEST LENGTH	Baghouse
OK-0118	HUGO GENERATING STA	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	2/9/2007	Particulate matter, filterable (FPM10)			0.015	LB/MMBTU	FILTERABLE	FABRIC FILTER BAGHOUSE
WY-0063	WYGEN 3	PC BOILER	2/5/2007	Particulate matter, filterable (FPM)			0.012	LB/MMBTU	3 X 120 MINUTE TEST	BAGHOUSE
IL-0107	DALLMAN POWER PLANT	DALLMAN 4 ELECTRICAL GENERATING UNIT	8/10/2006	Particulate matter, filterable (FPM)			0.012	LB/MMBTU	3-HOUR BLOCK AVERAGE	CONVENTIONAL DRY ESP FOLLOWED BY WET ESP.
TX-0499	SANDY CREEK ENERGY STATION	PULVERIZED CAOL BOILER	7/24/2006	Particulate matter, filterable (FPM10)			123	LB/H	1-HR	

Table D-2.4 Summary of Filterable PM BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
CO-0055	LAMAR LIGHT & POWER POWER PLANT	CIRCULATING FLUIDIZED BED BOILER	2/3/2006	Particulate matter, filterable (FPM10)			0.012	LB/MMBTU	DURATION OF TESTS	HIGH EFFICIENCY(MEMBRANE) LINED FABRIC FILTER BAGHAUSE FOR FILTEARABLE PARTICULATE MATTER. MAXIMIZATION OF HEAT EXTRACTION FROM COMBUSTION GASES PRIOR TO BAGHAUSE
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 2	1/27/2006	Particulate matter, filterable (FPM10)			0.0236	LB/MMBTU	30 DAYS ROLLING AVERAGE FILTABLE/COND.	KCPL SHALL INSTALL A FABRIC FILTRATION SYSTEM (BAGHOUSE) FOR THE UNIT 2 BOILER TO REDUCE PM10 EMISSIONS.
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	PULVERIZED COAL BOILER - UNIT 1	1/27/2006	Particulate matter, filterable (FPM10)			0.0244	LB/MMBTU	30 DAYS ROLLING AVERAGE	BAGHOUSE

Table D-2.5 Summary of Total PM10 and PM2.5 BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	(2) coal-fired boilers	12/20/2013	Particulate matter, total (TPM)	900	MW	0.03	LB/MMBTU		Electrostatic Precipitators and Wet Flue Gas Desulfurization
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	(2) coal-fired boilers	12/20/2013	Particulate matter, total (TPM10)	900	MW	0.03	LB/MMBTU		Electrostatic Precipitators and Wet Flue Gas Desulfurization
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	(2) coal-fired boilers	12/20/2013	Particulate matter, total (TPM2.5)	900	MW	0.03	LB/MMBTU		Electrostatic Precipitators and Wet Flue Gas Desulfurization
WY-0073	JIM BRIDGER POWER PLANT	Unit 3	6/17/2013	Particulate matter, total (TPM2.5)	6000	MMBTU/H	0.0205	LB/MMBTU	3-HR AVERAGE	Utilize existing WFGD and ESP
WY-0073	JIM BRIDGER POWER PLANT	Unit 3	6/17/2013	Particulate matter, total (TPM10)	6000	MMBTU/H	0.0418	LB/MMBTU	3-HR AVERAGE	Utilize existing WFGD and ESP
WY-0073	JIM BRIDGER POWER PLANT	Unit 4	6/17/2013	Particulate matter, total (TPM10)	6000	MMBtu	0.0397	LB/MMBTU	3-HR AVERAGE	Utilize existing WFGD and ESP
WY-0073	JIM BRIDGER POWER PLANT	Unit 4	6/17/2013	Particulate matter, total (TPM2.5)	6000	MMBtu	0.018	LB/MMBTU	3-HR AVERAGE	Utilize existing WFGD and ESP
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)--Startup & Shutdown ONLY	6/29/2011	Particulate matter, total (TPM2.5)	3030	MMBTU/H EACH	54.5	LB/H	EACH; BACT & SIP; SS ONLY	Pulse jet fabric filter
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	6/29/2011	Particulate matter, total (TPM10)	3030	MMBTU/H EACH	0.026	LB/MMBTU	EACH; TEST PROTOCOL	Pulset jet fabric filter
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	6/29/2011	Particulate matter, total (TPM2.5)	3030	MMBTU/H EACH	0.024	LB/MMBTU	EACH; TEST PROTOCOL; BACT	Pulse jet fabric filter
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) - EXCLUDING Startup & Shutdown	6/29/2011	Particulate matter, total (TPM2.5)	3030	MMBTU/H each	72.7	LB/H	EACH; TEST PROTOCOL; BACT&SIP	Pulse jet Fabric filter
MI-0403	HOLLAND BOARD OF PUBLIC WORKS-JAMES DEYOUNG PLANT	CFB boiler	2/11/2011	Particulate matter, total (TPM10)	865	MMBTU/H	0.025	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Fabric filter and fugitive dust control plan
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Particulate matter, total (TPM10)	8307	MMBTU/H	0.025	LB/MMBTU	12-MONTH ROLLING AVG	Fabric filter and wet scrubber
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Particulate matter, total (TPM10)	7624	MMBTU/H	0.024	LB/MMBTU	EACH, TEST	ESPs and wet flue gas desulfurization.
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Particulate matter, total (TPM)	6670	MMBTU/H	0.025	LB/MMBTU	ANNUAL / STACK TEST	fabric filter, spray dry adsorber for acid gases
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Particulate matter, total (TPM10)	8190	MMBTU/H	0.024	LB/MMBTU	TEST METHOD	FABRIC FILTER, HYDRATED LIME INJECTION
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	2 CIRCULATING FLUIDIZED BED BOILERS	6/30/2008	Particulate matter, total (TPM10)	3132	MMBTU/H	0.012	LB/MMBTU	3 HOURS	GOOD COMBUSTION PRACTICES AND BAGHOUSE
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	2 CIRCULATING FLUIDIZED BED BOILERS	6/30/2008	Particulate matter, total (TPM2.5)	3132	MMBTU/H	0.012	LB/MMBTU	3 HOURS	GOOD COMBUSTION PRACTICES AND BAGHOUSE
CO-0072	CRAIG ELECTRIC GENERATING STATION	Unit 3 Coal boiler	5/16/2007	Particulate matter, total (TPM10)			0.02	LB/MMBTU	AVE OVER STACK TEST LENGTH	Baghouse
CO-0072	CRAIG ELECTRIC GENERATING STATION	Unit 3 Coal boiler	5/16/2007	Particulate matter, total (TPM)			0.022	LB/MMBTU	AVE OVER STACK TEST LENGTH	Baghouse

Table D-2.6 H2SO4 BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WY-0073	JIM BRIDGER POWER PLANT	Unit 3	6/17/2013	Sulfuric Acid (mist, vapors, etc)	6000	MMBTU/H	0.004	LB/MMBTU	3-HR AVERAGE	Wet flue gas desulfurization
WY-0073	JIM BRIDGER POWER PLANT	Unit 4	6/17/2013	Sulfuric Acid (mist, vapors, etc)	6000	MMBtu	0.004	LB/MMBTU	3-HR AVERAGE	Utilize existing WFGD
MI-0400	WOLVERINE POWER	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	6/29/2011	Sulfuric Acid (mist, vapors, etc)	3030	MMBTU/H EACH	0.003	LB/MMBTU	EACH; TEST PROTOCOL; BACT & SIP	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	Coal-fired Boiler	12/30/2010	Sulfuric Acid (mist, vapors, etc)	8307	MMBTU/H	0.0037	LB/MMBTU	12-MONTH ROLLING	Wet scrubber
MI-0399	DETROIT EDISON--MONROE	Boiler Units 1, 2, 3 and 4	12/21/2010	Sulfuric Acid (mist, vapors, etc)	7624	MMBTU/H	0.005	LB/MMBTU	EACH, TEST	ESPs and wet flue gas desulfurization.
TX-0554	COLETO CREEK UNIT 2	Coal-fired Boiler Unit 2	5/3/2010	Sulfuric Acid (mist, vapors, etc)	6670	MMBTU/H	0.004	LB/MMBTU	ANNUAL / STACK TEST	spray dry adsorber/fabric filter
MI-0389	KARN WEADOCK GENERATING COMPLEX	BOILER	12/29/2009	Sulfuric Acid (mist, vapors, etc)	8190	MMBTU/H	0.004	LB/MMBTU	TEST METHOD	HYDRATED LIME INJECTION AND WET FGD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	BOILER (2), PULVERIZED COAL FIRED	10/8/2009	Sulfuric Acid (mist, vapors, etc)	5191	MMBTU/H	38.9	LB/H	AS A 3-HOUR AVERAGE EACH BOILER	WET FLUE GAS DESULFURIZATION
WY-0069	NAUGHTON PLANT	UNIT 1	5/20/2009	Sulfuric Acid (mist, vapors, etc)	1850	MMBTU/H	0.0014	LB/MMBTU		SO3 INJECTION LIMIT, 8 PPMV 30-DAY ROLLING
WY-0069	NAUGHTON PLANT	UNIT 2	5/20/2009	Sulfuric Acid (mist, vapors, etc)	2400	MMBTU/H	0.0005	LB/MMBTU		SO3 INJECTION LIMIT 8 PPMV 30 DAY ROLLING
WY-0069	NAUGHTON PLANT	UNIT 3	5/20/2009	Sulfuric Acid (mist, vapors, etc)	3700	MMBTU/H	0.0012	LB/MMBTU		SO3 INJECTION LIMIT 8PPMV 30 DAY ROLLING
AZ-0050	CORONADO GENERATING STATION	UNIT 2	1/22/2009	Sulfuric Acid (mist, vapors, etc)	4719	MMBTU	0.012	LB/MMBTU	3-HOUR AVERAGE	ULTRA LOW ACTIVITY CATALYST IN SCR
AR-0094	JOHN W. TURK JR. POWER PLANT	PC BOILER	11/5/2008	Sulfuric Acid (mist, vapors, etc)	6000	MMBTU/H	0.0042	LB/MMBTU	3 HOUR	DRY FLUE GAS DESULFURIZATION (SPRAY DRYER ABSORBER)
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	2 CIRCULATING FLUIDIZED BED BOILERS	6/30/2008	Sulfuric Acid (mist, vapors, etc)	3132	MMBTU/H	0.0035	LB/MMBTU		LIMESTONE AND FLUE GAS DESULFURIZATION
WY-0064	DRY FORK STATION	PC BOILER (ES1-01)	10/15/2007	Sulfuric Acid (mist, vapors, etc)			0.0025	LB/MMBTU	ANNUAL	CIRCULATING DRY SCRUBBER
MD-0038	BRANDON SHORES GENERATING STATION	BRANDON SHORES UNIT 1 & UNIT 2	6/2/2007	Sulfuric Acid (mist, vapors, etc)			0.027	LB/MMBTU	3-HOUR AVERAGE	SORBENT INJECTION PLUS FABRIC FILTER
FL-0295	CRYSTAL RIVER POWER PLANT	FFFSG UNITS 4 AND 5	5/18/2007	Sulfuric Acid (mist, vapors, etc)			0.009	LB/MMBTU		ALKALI INJECTION SYSTEM
OK-0118	HUGO GENERATING STA	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	2/9/2007	Sulfuric Acid (mist, vapors, etc)			0.0037	LB/MMBTU		WET FLUE GAS DESULFURIZATION
IL-0107	DALLMAN POWER PLANT	DALLMAN 4 ELECTRICAL GENERATING UNIT	8/10/2006	Sulfuric Acid (mist, vapors, etc)			0.005	LB/MMBTU	3-HOUR BLOCK AVERAGE	CONVENTIONAL SCRUBBER FOLLOWED BY WET ESP.
TX-0499	SANDY CREEK ENERGY STATION	PULVERIZED CAOL BOILER	7/24/2006	Sulfuric Acid (mist, vapors, etc)			127	LB/H		

Table D-2.7 CO2e BACT Determination for Coal C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IA-0101	OTTUMWA GENERATING STATION	Boiler #1, Boiler, Dry Bottom Tangentially Fired	1/12/2012	Carbon Dioxide Equivalent (CO2e)	8669	MMBtu/hr	8000325	T/YR	ROLLING 12 MONTH TOTAL	Good Combustion Practices
IA-0101	OTTUMWA GENERATING STATION	Boiler #1, Boiler, Dry Bottom Tangentially Fired	1/12/2012	Carbon Dioxide	8669	MMBtu/hr	2927.1	LB/MWH (NET)	30-DAY ROLLING AVERAGE	Good Combustion Practices

Table D-3.1 Summary of NOx BACT Determination for Natural Gas C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0334	ANCLOTE POWER GENERATING FACILITY	Fossil Fuel Fired Steam Generators	9/14/2012	Nitrogen Oxides (NOx)	556.2	MW	0.3	LB/MMBTU	12-MONTH ROLLING AVERAGE	For Units 1 and 2, the applicant shall incorporate combustion controls based on good combustion practices for CO and NOX including, but not limited to, combustion by air staging achieved by close coupled overfire air (CCOFA)
LA-0364	FG LA COMPLEX	Boilers	1/6/2020	Nitrogen Oxides (NOx)	1200	mm btu/h	0.01	LB/MMBTU	12-MONTH ROLLING AVERAGE	SCR and LNB

Table D-3.2 Summary of CO BACT Determination for Natural Gas C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0334	ANCLOTE POWER GENERATING FACILITY	Fossil Fuel Fired Steam Generators	9/14/2012	Carbon Monoxide	556.2	MW	0.15	LB/MMBTU	30-OPERATING DAY ROLLING AVERAGE	For Units 1 and 2, the applicant shall incorporate combustion controls based on good combustion practices for CO and NOX including, but not limited to, combustion by air staging achieved by close coupled overfire air (CCOFA).
LA-0227	CLECO RODEMACHER POWER STATION	UNIT 2 BOILER (1-74)	5/8/2008	Carbon Monoxide	5445	MMBTU/H	3000	LB/H	HOUR	LOW NOX BURNERS, OVERFIRE AIR, GOOD COMBUSTION PRACTICES
LA-0364	FG LA COMPLEX	Boilers	1/6/2020	Carbon Monoxide	1200	mm btu/h	0.037	LB/MMBTU		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
OK-0150	PSO SOUTHWESTERN POWER STATION	BOILER	1/17/2013	Carbon Monoxide	3290	MMBTUH	0.15	LB/MMBTU	ANNUAL	
OK-0161	PSO SOUTHWESTERN POWER STA	Boiler #3	3/31/2014	Carbon Monoxide	3290	MMBTUH	0.465	LB/MMBTU	30-DAY AVG	
OK-0168	SEMINOLE GNRTNG STA	NATURAL GAS-FIRED BOILER (>250MMBTUH)	5/5/2015	Carbon Monoxide	16456	MMBTUH	0.465	LB/MMBTU	30-DAY ROLLING AVERAGE	NO CONTROLS FEASIBLE;GOOD COMBUSTION PRACTICES

Table D-3.3 Summary of VOC BACT Determination for Natural Gas C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Boilers	1/6/2020	Volatile Organic Compounds (VOC)	1200	mm btu/h	0.0055	LB/MMBTU		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD

Table D-3.4 Summary of Total PM10 and PM2.5 BACT Determination for Natural Gas C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Boilers	1/6/2020	Particulate matter, total (TPM10)	1200	mm btu/h	6.81	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0364	FG LA COMPLEX	Boilers	1/6/2020	Particulate matter, total (TPM2.5)	1200	mm btu/h	6.81	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.

Table D-3.5 Summary of CO2e BACT Determination for Natural Gas C2 Boiler

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Utility Boilers 1 & 2	1/6/2020	Carbon Dioxide Equivalent (CO2e)	1200 ea	MMBtu/hr	615294 ea	tpy	Annual	Use of natural gas or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Carbon Monoxide	50	MMBTU/H	50	PPMV	3-HR AVG @ 15 % O2	
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Carbon Monoxide	17.5	MMBTU/H	0.08	LB/MMBTU		GCP
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Carbon Monoxide	24.59	MMBTU/H	0.08	LB/MMBTU		GCP
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Carbon Monoxide	90.5	MMBtu/hr	0.037	LB/MMBTU		
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Carbon Monoxide	53.7	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Carbon Monoxide	53.7	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Carbon Monoxide	50.4	MMBTU/hr	0.075	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Carbon Monoxide	15	MMBTU/hr each	0.084	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Carbon Monoxide	0		0.084	LB/MMBTU		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Auxiliary Boiler, 99.8 MMBtu/hr	03/09/2016	Carbon Monoxide	99.8	MMBtu/hr	0.08	LB/MMBTU		Proper combustion prevents CO
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Carbon Monoxide	99.8	MMBtu/hr	0.08	LB/MMBTU		Clean fuel

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Carbon Monoxide	60	MMBtu/hour	0.08	LB/MMBTU		Good combustion practices and low-NOx burners
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Carbon Monoxide	60	MMBtu/hour	0.08	LB/MMBTU		Good combustion practices and low-NOx burners
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Carbon Monoxide	96	mmBtu/hr	0.037	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Carbon Monoxide	96	mmBtu/hr	0.037	LB/MMBTU	3-HOUR	Good combustion practice
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Carbon Monoxide	80	mmBtu/hour	0.037	POUNDS/MM BTU	ROLLING 3-OPERATING HOUR	Good burner design and good combustion practices.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Carbon Monoxide	50	MMBtu/hr	61	LB/MMSCF		good combustion practices
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Carbon Monoxide	96	MMBtu per hour	0.037	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Carbon Monoxide	48.2	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Carbon Monoxide	17.7	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Carbon Monoxide	50.4	MMBtu/hr	61	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Carbon Monoxide	18	MMBtu/hr, each	84	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Carbon Monoxide	94	mm btu/h	26.21	LB/H		Good combustion practices and oxidation catalyst.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Carbon Monoxide	80	mm BTU/h	0.05	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63 Subpart DDDDD.
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Carbon Monoxide	42	MMBTU/H	0.037	LB/MMBTU	3-HOUR BLOCK AVERAGE	GOOD COMBUSTION PRACTICES

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Carbon Monoxide	6	MMBTU/H	0.08	LB/MMBTU	TEST PROTOCOL	Good combustion practices and clean burn fuel (pipeline quality natural gas)
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Carbon Monoxide	83.5	MMBTU/H	0.077	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Carbon Monoxide	3	MMBTU/H	84	LB/MMSCF	EACH BOILER	Good combustion practices and clean burn fuel (pipeline quality natural gas).
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Carbon Monoxide	61.5	MMBTU/h	0.08	LB/MMBTU	HOURLY	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Carbon Monoxide	99.9	MMBTU/H	0.075	LB/MMBTU	HOURLY	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at & 99MMBTU/H	12/21/2018	Carbon Monoxide	99	MMBTU/H	50	PPM	@3%O2; HOURLY	Good combustion practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Carbon Monoxide	80	MMBTU/H	0.037	LB/MMBTU	HOURLY; EACH BOILER	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Carbon Monoxide	50	MMBTU/H	50	PPM	AT 3% O2; HOURLY	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices.
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Carbon Monoxide	50	MMBTU/H	50	PPM	PPMVD AT 3%O2; HOURLY	Good combustion practices.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Carbon Monoxide	687	MMCFT/YR	2.88	LB/H	AV OF THREE ONE H STACK TESTS	Use of good combustion practices and use of natural gas a clean burning fuel

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Carbon Monoxide	4000	H/YR	3.61	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Carbon Monoxide	60	MMBTU/H	0.0375	LB/MMBTU	1 H	good combustion practice
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Carbon Monoxide	34	MMBTU/H	1.87	LB/H		Good combustion controls
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Carbon Monoxide	99	MMBTU/H	7.92	LB/H		Good combustion controls and natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Carbon Monoxide	37.8	MMBTU/H	2.08	LB/H		Good combustion controls
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Carbon Monoxide	37.8	MMBTU/H	2.08	LB/H		good combustion controls
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Carbon Monoxide	26.8	MMBTU/H	0.99	LB/H		Good combustion controls
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Carbon Monoxide	44.55	MMBTU/H	1.67	LB/H		Good combustion practices
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Carbon Monoxide	80	MMBTU/H	2.48	LB/H		Good combustion practices
OH-0383	PETMIN USA INCORPORATED	Startup boiler (B001)	07/17/2020	Carbon Monoxide	15.17	MMBTU/H	1.25	LB/H		good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Carbon Monoxide	29.4	MMBTU/H	33	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
OK-0168	SEMINOLE GNRTNG STA	NATURAL GAS-FIRED BOILER (&100MMBTUH)	05/05/2015	Carbon Monoxide	40.4	MMBTUH	0.0075	LB/MMBTU	3-HOUR AVERAGE (TEST)	NO CONTROLS FEASIBLE;GOOD COMBUSTION PRACTICES
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Carbon Monoxide	62.04	MCF/hr	0.06	LB/MMBTU		Good combustion practices

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Carbon Monoxide	13.31	MMBtu/hr	0.037	LB/MMBTU		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Carbon Monoxide	92.4	MMBtu/hr	0.037	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Carbon Monoxide	55.4	MMBtu/hr	0.037	LB/MMBTU		
*PA-0316	RENOVO ENERGY CENTER, LLC	Auxiliary Boiler	01/26/2018	Carbon Monoxide	118800	MMBtu/12 month period	0.036	LB	MMBTU	
*PA-0319	RENAISSANCE ENERGY CENTER	NATURAL GAS FIRED AUXILIARY BOILER	08/27/2018	Carbon Monoxide	88	MMBtu/hr	0.055	LB/MMBTU	HR	Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance.
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	Boiler No. 2	05/21/2019	Carbon Monoxide	0		0.0375	LB/MMBTU		Work Practice Standards
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	boiler	12/19/2014	Carbon Monoxide	80	MMBTU/H	0.037	LB/MMBTU	3-HR ROLLING AVERAGE	low-NOx burners
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	Commercial/Institutional Size Boilers (&100 MMBtu) natural gas	06/18/2015	Carbon Monoxide	73.3	MMBTU/H	50	PPM	ROLLING 3-HR AVERAGE	
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Monoxide	95.7	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practice to ensure complete combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Monoxide	13.2	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practice to ensure complete combustion.
WI-0283	AFE, INC. LCM PLANT	B01-B12, Boilers	04/24/2018	Carbon Monoxide	28	mmBTU/hr	25	PPMVD		Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Carbon Monoxide	28	mmBTU	25	PPMVD		Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Carbon Monoxide	100	MMBTU/H	0.0037	LB/MMBTU		Oxidation Catalyst and operate and maintain boiler according to the manufacturer's recommendations.

Table D-4.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Carbon Monoxide	14.67	MMBTU/H	0.04	LB/MMBTU	HEAT INPUT	Shall be operated for no more than 500 hours and combust only pipeline quality natural gas.
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Carbon Monoxide	77.8	mmBtu/hr	2.88	LB/HR		Good Combustion Practices
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Carbon Monoxide	111.9	mmBtu/hr	4.14	LB/HR		Good Combustion Practices
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	Auxiliary Boiler	07/16/2014	Carbon Monoxide	25.06	MMBtu/h	0.0375	LB/MMBTU	3 HOUR AVERAGE	good combustion

Table D-4.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.0054	LB/MMBTU	3-HR AVG	
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Volatile Organic Compounds (VOC)	17.5	MMBTU/H	0.006	LB/MMBTU		GCP
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Volatile Organic Compounds (VOC)	24.59	MMBTU/H	0.006	LB/MMBTU		GCP
AL-0312	BELK CHIP-N-SAW FACILITY	60 MMBTU/HR NATURAL GAS-FIRED BOILER (ES-008)	05/26/2016	Volatile Organic Compounds (VOC)	60	MMBTU/H	0.0054	LB/MMBTU INPUT		GOOD COMBUSTION PRACTICES
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Volatile Organic Compounds (VOC)	90.5	MMBtu/hr	0.004	LB/MMBTU		
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Volatile Organic Compounds (VOC)	53.7	MMBTU/HR	0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Volatile Organic Compounds (VOC)	53.7	MMBTU/HR	0.054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Volatile Organic Compounds (VOC)	50.4	MMBTU/hr	0.0026	LB/HR		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Volatile Organic Compounds (VOC)	15	MMBTU/hr each	0.0055	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Volatile Organic Compounds (VOC)	0		0.0055	LB/MMBTU		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Volatile Organic Compounds (VOC)	80	mmBtu/hour	0.0015	POUNDS/MM BTU	ROLLING 3-OPERATING HOUR	Good burner design and good combustion practices
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Volatile Organic Compounds (VOC)	50	MMBtu/hr	0.0054	LB/MMBTU		good combustion practices and natural gas fuel (clean fuel)

Table D-4.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Volatile Organic Compounds (VOC)	73.6	MMBtu/hr (each)	5.5	LB/MMCF (EACH)		Good Combustion Practices
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Volatile Organic Compounds (VOC)	96	MMBtu per hour	0			
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Volatile Organic Compounds (VOC)	48.2	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Volatile Organic Compounds (VOC)	17.7	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Volatile Organic Compounds (VOC)	50.4	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 â€“ Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Volatile Organic Compounds (VOC)	18	MMBtu/hr, each	5.5	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Volatile Organic Compounds (VOC)	94	mm btu/h	13.37	LB/H		Good combustion practices and oxidation catalyst
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Volatile Organic Compounds (VOC)	80	mm BTU/h	0.0054	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63 Subpart DDDDD.
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Volatile Organic Compounds (VOC)	42	MMBTU/H	0.003	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Volatile Organic Compounds (VOC)	83.5	MMBTU/H	0.008	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Volatile Organic Compounds (VOC)	61.5	MMBTU/h	0.004	LB/MMBTU	HOURLY	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Volatile Organic Compounds (VOC)	99.9	MMBTU/H	0.008	LB/MMBTU	HOURLY	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Volatile Organic Compounds (VOC)	99	MMBTU/H	0.5	LB/H	HOURLY	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Volatile Organic Compounds (VOC)	80	MMBTU/H	0.0054	LB/MMBTU	HOURLY; EACH BOILER	Good combustion practices.
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.3	LB/H	HOURLY	Good combustion practices

Table D-4.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	HOURLY	Good combustion practices
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.3	LB/H	HOURLY	Good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Boiler A	11/21/2022	Volatile Organic Compounds (VOC)	84	MMBtu/hr	0.52	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0064	NORFOLK CRUSH, LLC	Boiler B	11/21/2022	Volatile Organic Compounds (VOC)	84	MMBtu/hr	0.52	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Volatile Organic Compounds (VOC)	687	MMCFT/YR	0.32	LB/H	AV OF THREE ONE H STACK TESTS	Use of good combustion practices and use of natural gas a clean burning fuel
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Volatile Organic Compounds (VOC)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Volatile Organic Compounds (VOC)	60	MMBTU/H	0.0015	LB/MMBTU	1 H	good combustion practice
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Volatile Organic Compounds (VOC)	34	MMBTU/H	0.2	LB/H		Good combustion controls
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Volatile Organic Compounds (VOC)	99	MMBTU/H	0.59	LB/H		Good combustion controls and natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Volatile Organic Compounds (VOC)	37.8	MMBTU/H	0.23	LB/H		Good combustion controls
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Volatile Organic Compounds (VOC)	37.8	MMBTU/H	0.23	LB/H		good combustion controls
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Volatile Organic Compounds (VOC)	26.8	MMBTU/H	0.13	LB/H		Good combustion controls
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Volatile Organic Compounds (VOC)	44.55	MMBTU/H	0.16	LB/H		Good combustion practices
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Volatile Organic Compounds (VOC)	80	MMBTU/H	0.248	LB/H		Good combustion practices
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Volatile Organic Compounds (VOC)	29.4	MMBTU/H	4.86	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Volatile Organic Compounds (VOC)	62.04	MCF/hr	0.004	LB/MMBTU		Good combustion practices and FGR

Table D-4.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Volatile Organic Compounds (VOC)	13.31	MMBtu/hr	0.005	LB/MMBTU	30-DAY ROLLING BASIS	
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Volatile Organic Compounds (VOC)	92.4	MMBtu/hr	0.004	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Volatile Organic Compounds (VOC)	55.4	MMBtu/hr	0.005	LB/MMBTU		
*PA-0316	RENOVO ENERGY CENTER, LLC	Auxiliary Boiler	01/26/2018	Volatile Organic Compounds (VOC)	118800	MMBtu/12 month period	0.005	LB	MMBTU	
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	Boiler No. 2	05/21/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Work Practice Standards
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Volatile Organic Compounds (VOC)	14.27	MMBTU/hr	5.5	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	Commercial/Institutional Size Boilers (<100 MMBtu) â€" natural gas	06/18/2015	Volatile Organic Compounds (VOC)	73.3	MMBTU/H	4	PPM	1-HR AVG	
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Volatile Organic Compounds (VOC)	95.7	MMBTU/H	5.42	T/YR		Good combustion practice to ensure complete combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Volatile Organic Compounds (VOC)	13.2	MMBTU/H	0.3	T/YR		Good combustion practice to ensure complete combustion.
TX-0813	ODESSA PETROCHEMICAL PLANT	small Boiler	11/22/2016	Volatile Organic Compounds (VOC)	39.9	MMBtu/hr	0.0005	MMBTU/HR		best combustion practices
TX-0877	SWEENY REFINERY	Isostripper Reboiler (heater)	01/08/2020	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Good combustion practices, use of natural gas fuel for the project heater
VA-0327	PERDUE GRAIN AND OILSEED, LLC	(4) 27 MMBtu/hr boilers, Natural gas and No. 2 fuel oi	07/12/2017	Volatile Organic Compounds (VOC)	0		0.1	LB/HR		
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	Natural gas-fied boiler (Boiler B01)	09/06/2018	Volatile Organic Compounds (VOC)	35	mmBtu/hr	0.0055	LB/MMBTU		Good combustion practices, use only natural gas, equip boiler with Low NOx burners and flue gas recirculation
WI-0283	AFE, INC. â€"LCM PLANT	B01-B12, Boilers	04/24/2018	Volatile Organic Compounds (VOC)	28	mmBTU/hr	0.0036	LB/MMBTU		Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Volatile Organic Compounds (VOC)	28	mmBTU	0.0036	LB/MMBTU		Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.
WI-0289	GEORGIA-PACIFIC CONSUMER PRODUCTS LLC	B98 & B99 Natural Gas Fired Temporary Boilers	04/01/2019	Volatile Organic Compounds (VOC)	95	mmBTU/hr	0.0055	LB/MMBTU		Good Combustion Practices

Table D-4.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Volatile Organic Compounds (VOC)	8.5	MMBtu/H	0.0055	LB/MMBTU		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Volatile Organic Compounds (VOC)	100	MMBTU/H	0.0027	LB/MMBTU		Oxidation catalyst and operate and maintain boiler according to manufacturer's recommendations.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Volatile Organic Compounds (VOC)	14.67	MMBTU/H	0	SEE NOTES		Shall be operated for no more than 500 hours and combust only pipeline quality natural gas.
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Volatile Organic Compounds (VOC)	77.8	mmBtu/hr	0.62	LB/HR		Use of Natural Gas, Good Combustion Practices
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Volatile Organic Compounds (VOC)	111.9	mmBtu/hr	0.9	LB/HR		Use of Natural Gas, Good Combustion Practices

Table D-4.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Nitrogen Oxides (NO_x)	13.31	MMBtu/hr	0.006	LB/MMBTU	30-DAY ROLLING AVERAGE BASIS	SCR and ultra low NOx burners, Fired only on natural gas supplied by a public utility.
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Nitrogen Oxides (NO_x)	17.7	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		Low NOx burners, Combustion of clean fuel, and Good Combustion Practices
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Nitrogen Oxides (NO_x)	13.2	MMBTU/H	0.1	LB/MMBTU		
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Nitrogen Oxides (NO_x)	6	MMBTU/H	14	PPMVOL	AT 15%O2; TEST PROTOCOL	Ultra low NOx burners and good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Nitrogen Oxides (NO_x)	3	MMBTU/H	20	PPM AT 3% O2	EACH 3 MMBTU/H BOILER	Ultra-low NOx burners and good combustion practices.
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Nitrogen Oxides (NO_x)	17.5	MMBTU/H	30	PPMVD	3% O2	LOW NOX BURNER FLUE GAS RECIRCULATION GCP
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 â€" Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Nitrogen Oxides (NO_x)	18	MMBtu/hr, each	50	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low-NOx burners.
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		Low NOx burners
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Nitrogen Oxides (NO_x)	15	MMBTU/hr each	0.1	LB/MMBTU	3-HR	Low Nox Burners
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Nitrogen Oxides (NO_x)	15.17	MMBTU/H	0.634	LB/H		Low-NOX burners, good combustion practices and the use of natural gas

Table D-4.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Nitrogen Oxides (NO_x)	14.67	MMBTU/H	0.04	LB/MMBTU	AVG. OVER ANY CONSECUTIVE 3-HR PERIOD	Low NOx burners, flue gas recirculation, shall be operated for no more than 500 hours, and shall combust only pipeline quality natural gas.

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Particulate matter, filterable (FPM10)	90.5	MMBtu/hr	0.0075	LB/MMBTU	3 HOUR AVG	
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Particulate matter, filterable (FPM2.5)	90.5	MMBtu/hr	0.0075	LB/MMBTU	3 HOUR AVG	
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Particulate matter, filterable (FPM2.5)	60	MMBtu/hour	0			Clean fuels
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Particulate matter, filterable (FPM2.5)	60	MMBtu/hour	1.4	GR. S/100 SCF NG	FUEL RECORDKEEPING	
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Particulate matter, filterable (FPM10)	60	MMBtu/hour	1.4	GR. S/100 SCF NG	FUEL RECORDKEEPING	Clean Fuels
*PA-0316	RENOVO ENERGY CENTER, LLC	Auxiliary Boiler	01/26/2018	Particulate matter, filterable (FPM10)	118800	MMBtu/12 month period	0.0019	LB	MMBTU	

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Particulate matter, total (TPM10)	50	MMBTU/H	0.0074	LB/MMBTU	3-HR AVG	Limited Use (200 hr/yr)
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.0074	LB/MMBTU	3-HR AVG	
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Particulate matter, total (TPM10)	53.7	MMBTU/HR	0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Particulate matter, total (TPM2.5)	53.7	MMBTU/HR	0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Particulate matter, total (TPM10)	53.7	MMBTU/HR	6.8	X10^-4 LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Particulate matter, total (TPM2.5)	53.7	MMBTU/HR	6.8	X10^-4 LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0007	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0007	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Particulate matter, total (TPM10)	50.4	MMBTU/hr	0.0076	LB/MMBTU	3-HR	Good combustion practices

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Particulate matter, total (TPM2.5)	50.4	MMBTU/hr	0.0076	LB/MMBTU	3-HR	Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Particulate matter, total (TPM10)	15	MMBTU/hr each	0.0076	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Particulate matter, total (TPM2.5)	15	MMBTU/hr each	0.0076	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Particulate matter, total (TPM10)	0		0.0076	GR/DSCF		Good Combustion Practice
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Particulate matter, total (TPM2.5)	0		0.0076	GR/DSCF		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0007	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0007	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Particulate matter, total (TPM10)	99.8	MMBtu/hr	0			Clean fuels
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Particulate matter, total (TPM10)	60	MMBtu/hour	0			Clean fuels
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Particulate matter, total (TPM10)	80	mmBtu/hour	0.0075	POUNDS/MM BTU	ROLLING 3-OPERATING HOUR	Good combustion practices.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Particulate matter, total (TPM10)	50	MMBtu/hr	0.0007	LB/MMBTU		good combustion practices and only pipeline quality natural gas fuel shall be combusted
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Particulate matter, total (TPM2.5)	50	MMBtu/hr	0.0007	LB/MMBTU		good combustion practices and only pipeline quality natural gas fuel shall be combusted
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Particulate matter, total (TPM10)	73.6	MMBtu/hr (each)	7.6	LB/MMCF (EACH)		Good Combustion Practices
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Particulate matter, total (TPM2.5)	73.6	MMBtu/hr (each)	7.6	LB/MMCF (EACH)		Good Combustion Practices
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Particulate matter, total (TPM10)	96	MMBtu per hour	0.0075	LB PER MMBTU	BASED ON A 3-HR AVERAGE	

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Particulate matter, total (TPM2.5)	96	MMBtu per hour	0.0075	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Particulate matter, total (TPM2.5)	18.6	MMBTU/HR	0.005	LB PER MMBTU		
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Particulate matter, total (TPM10)	18.6	MMBTU/HR	0.005	LB PER MMBTU		
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Particulate matter, total (TPM10)	48.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Particulate matter, total (TPM2.5)	48.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Particulate matter, total (TPM10)	17.7	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Particulate matter, total (TPM2.5)	17.7	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Particulate matter, total (TPM10)	50.4	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Particulate matter, total (TPM2.5)	50.4	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Particulate matter, total (TPM10)	18	MMBtu/hr, each	7.6	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Particulate matter, total (TPM2.5)	18	MMBtu/hr, each	7.6	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Particulate matter, total (TPM10)	94	mm btu/h	0.61	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Particulate matter, total (TPM2.5)	94	mm btu/h	0.61	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Particulate matter, total (TPM10)	80	mm BTU/h	0.0074	LB/MM BTU		Exclusive combustion of natural gas and good combustion practices.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Particulate matter, total (TPM2.5)	80	mm BTU/h	0.0074	LB/MM BTU		Combusts exclusively natural gas and good combustion practices.
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Particulate matter, total (TPM10)	42	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Particulate matter, total (TPM2.5)	42	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Particulate matter, total (TPM10)	6	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Particulate matter, total (TPM2.5)	6	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Particulate matter, total (TPM10)	83.5	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WIL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Particulate matter, total (TPM2.5)	83.5	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Particulate matter, total (TPM10)	3	MMBTU/H	0.52	LB/MMSCF	EACH BOILER	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Particulate matter, total (TPM2.5)	3	MMBTU/H	0.52	LB/MMSCF	EACH BOILER	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Particulate matter, total (TPM10)	61.5	MMBTU/h	0.46	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Particulate matter, total (TPM2.5)	61.5	MMBTU/h	0.46	LB/H	HOURLY	Good combustion practices.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Particulate matter, total (TPM10)	99.9	MMBTU/H	0.007	LB/MMBTU	HOURLY	Good combustion practices, low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Particulate matter, total (TPM2.5)	99.9	MMBTU/H	0.007	LB/MMBTU	HOURLY	Good combustion practices, low sulfur fuel
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Particulate matter, total (TPM10)	99	MMBTU/H	0.74	LB/H	HOURLY	Good combusion practices
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Particulate matter, total (TPM2.5)	99	MMBTU/H	0.74	LB/H	HOURLY	Good combustion practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Particulate matter, total (TPM10)	80	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH BOILER	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Particulate matter, total (TPM2.5)	80	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH BOILER	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Particulate matter, total (TPM10)	50	MMBTU/H	0.74	LB/H	HOURLY	Good combustion practices.
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices.
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Particulate matter, total (TPM10)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Boiler A	11/21/2022	Particulate matter, total (TPM10)	84	MMBtu/hr	0.26	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0064	NORFOLK CRUSH, LLC	Boiler B	11/21/2022	Particulate matter, total (TPM10)	84	MMBtu/hr	0.26	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 1	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 2	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 3	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Particulate matter, total (TPM10)	687	MMCFT/YR	0.4	LB/H	AV OF THREE ONE HOUR STACK TESTS	use of natural gas a clean burning fuel

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Particulate matter, total (TPM2.5)	687	MMCFT/YR	0.4	LB/H	AV OF THREE ONE HOUR STACK TESTS	use of natural gas a clean burning fuel
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Particulate matter, total (TPM10)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Particulate matter, total (TPM2.5)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Particulate matter, total (TPM10)	34	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Particulate matter, total (TPM2.5)	34	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Particulate matter, total (TPM10)	99	MMBTU/H	5.94	LB/H		natural gas/ultra low sulfur diesel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Particulate matter, total (TPM2.5)	99	MMBTU/H	5.94	LB/H		natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Particulate matter, total (TPM10)	37.8	MMBTU/H	0.3	LB/H		Low sulfur fuel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Particulate matter, total (TPM2.5)	37.8	MMBTU/H	0.3	LB/H		Low sulfur fuel
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Particulate matter, total (TPM10)	37.8	MMBTU/H	0.3	LB/H		low sulfur fuel
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Particulate matter, total (TPM2.5)	37.8	MMBTU/H	0.3	LB/H		low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Particulate matter, total (TPM10)	26.8	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Particulate matter, total (TPM2.5)	26.8	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Particulate matter, total (TPM10)	44.55	MMBTU/H	0.33	LB/H		Pipeline quality natural gas

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Particulate matter, total (TPM2.5)	44.55	MMBTU/H	0.33	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Particulate matter, total (TPM10)	80	MMBTU/H	0.48	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Particulate matter, total (TPM2.5)	80	MMBTU/H	0.48	LB/H		Pipeline quality natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Particulate matter, total (TPM10)	15.17	MMBTU/H	0.113	LB/H	SEE NOTES.	Good combustion practices and the use of natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Particulate matter, total (TPM2.5)	15.17	MMBTU/H	0.113	LB/H	SEE NOTES.	Good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Particulate matter, total (TPM10)	29.4	MMBTU/H	0.46	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Particulate matter, total (TPM2.5)	29.4	MMBTU/H	0.38	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxiliary Boiler	06/15/2015	Particulate matter, total (TPM10)	62.04	MCF/hr	0.005	LB/MMBTU		Good combustion practices and low sulfur fuels
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Particulate matter, total (TPM10)	13.31	MMBtu/hr	0.007	LB/MMBTU		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Particulate matter, total (TPM2.5)	13.31	MMBtu/hr	0.007	LB/MMBTU		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Particulate matter, total (TPM10)	92.4	MMBtu/hr	0.007	LB/MMBTU		ULSD and good combustion practices
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Particulate matter, total (TPM2.5)	92.4	MMBtu/hr	0.007	LB/MMBTU		ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Particulate matter, total (TPM10)	55.4	MMBtu/hr	0.007	LB/MMBTU		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Particulate matter, total (TPM2.5)	55.4	MMBtu/hr	0.007	LB/MMBTU		
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Particulate matter, total (TPM10)	14.27	MMBTU/hr	7.6	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Particulate matter, total (TPM2.5)	14.27	MMBTU/hr	7.6	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM10)	95.7	MMBTU/H	7.49	T/YR		Use of gaseous fuel with efficient combustion.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM2.5)	95.7	MMBTU/H	7.49	T/YR		Use of gaseous fuel with efficient combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM10)	13.2	MMBTU/H	0.4	T/YR		Good combustion practice to ensure complete combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM2.5)	13.2	MMBTU/H	4	T/YR		Good combustion practice to ensure complete combustion.
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Particulate matter, total (TPM10)	76.6	MMBtu/hr	0.0078	LB	MMBTU	
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Particulate matter, total (TPM2.5)	76.6	MMBtu/hr	0.0078	LB	MMBTU	
WI-0283	AFE, INC. â€"LCM PLANT	B01-B12, Boilers	04/24/2018	Particulate matter, total (TPM10)	28	mmBTU/hr	0.0075	LB/MMBTU		Good Combustion Practices
WI-0283	AFE, INC. â€"LCM PLANT	B01-B12, Boilers	04/24/2018	Particulate matter, total (TPM2.5)	28	mmBTU/hr	0.0075	LB/MMBTU		Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Particulate matter, total (TPM10)	28	mmBTU	0.0075	LB/MMBTU		Good Combustion Practices and The Use of Pipeline Quality Natural Gas
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Particulate matter, total (TPM2.5)	28	mmBTU	0.0075	LB/MMBTU		Good Combustion Practices and The Use of Pipeline Quality Natural Gas
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Particulate matter, total (TPM10)	100	MMBTU/H	0.01	LB/MMBTU		Only combust pipeline quality natural gas and operate and maintain boiler according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Particulate matter, total (TPM2.5)	100	MMBTU/H	0.01	LB/MMBTU		Only combust pipeline quality natural gas and operate and maintain B02 according to the manufacturer's recommendations.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Particulate matter, total (TPM10)	14.67	MMBTU/H	0.008	LB/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas, can be operated for no more than 500 hours.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Particulate matter, total (TPM2.5)	14.67	MMBTU/H	0.008	LB/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas, can be operated for no more than 500 hours.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM2.5)	8.72	mmBtu/hr	0			Limited to natural gas
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM10)	8.72	mmBtu/hr	0			Limited to natural gas

Table D-4.6 Summary of H_2SO_4 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Sulfuric Acid (mist, vapors, etc)	99.8	MMBtu/hr	0			Clean fuels
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Sulfuric Acid (mist, vapors, etc)	60	MMBtu/hour	0			Clean fuels
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Sulfuric Acid (mist, vapors, etc)	60	MMBtu/hour	1.4	GR. S/100 SCF NG	FUEL RECORDKEEPING	Limited sulfur content in fuel
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Sulfuric Acid (mist, vapors, etc)	96	mmBtu/hr	0.1	LB/HR		Good combustion practice
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Sulfuric Acid (mist, vapors, etc)	96	mmBtu/hr	0.1	POUNDS/HOUR		Good combustion practice
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Sulfuric Acid (mist, vapors, etc)	80	mmBtu/hour	0.02	POUNDS/MMBTU	ROLLING 3-OPERATING HOUR	Use of only natural gas with a sulfur content of no greater than 0.5 grains (gr)/100 standard cubic feet (scf).
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Sulfuric Acid (mist, vapors, etc)	96	MMBtu per hour	0.0001	LB PER MMBTU	BASED ON A 3-HOUR AVERAGE	
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Sulfuric Acid (mist, vapors, etc)	42	MMBTU/H	0.004	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Sulfuric Acid (mist, vapors, etc)	99.9	MMBTU/H	0.34	GR S/100 SCF	FUEL SUPPLIER RECORDS	Good combustion practices, low sulfur fuel
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Sulfuric Acid (mist, vapors, etc)	687	MMCFT/YR	0.02	LB/H		Use of natural gas a low sulfur fuel
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Sulfuric Acid (mist, vapors, etc)	4000	H/YR	0.01	LB/H		USE OF NATURAL GAS A CLEAN BURNING AND LOW SULFUR FUEL
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Sulfuric Acid (mist, vapors, etc)	60	MMBTU/H	1.1	10-4 LB/MMBTU	1 H	natural gas with maximum sulfur content 0.4 grains/100 dscf

Table D-4.6 Summary of H_2SO_4 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	34	MMBTU/H	0.004	LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	99	MMBTU/H	0.011	LB/H		natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	37.8	MMBTU/H	0.0087	LB/H		Low sulfur fuel
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	37.8	MMBTU/H	0.004	LB/H		low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	26.8	MMBTU/H	0.003	LB/H		Low sulfur fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	44.55	MMBTU/H	0.004	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	80	MMBTU/H	0.018	LB/H		Pipeline quality natural gas
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Sulfuric Acid (mist, vapors, etc)	62.04	MCF/hr	0	LB/MMBTU		Good combustion practices and low sulfur fuels
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Sulfuric Acid (mist, vapors, etc)	13.31	MMBtu/hr	0.0001	LB/MMBTU		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Sulfuric Acid (mist, vapors, etc)	92.4	MMBtu/hr	0.0011	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Sulfuric Acid (mist, vapors, etc)	55.4	MMBtu/hr	0.0001	LB/MMBTU		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	100	MMBTU/H	0.01	LB/H		Only combust pipeline quality natural gas and operate and maintain to the manufacturer's recommendations.

Table D-4.6 Summary of H_2SO_4 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	14.67	MMBTU/H	0			Combust only pipeline quality natural gas.
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Sulfuric Acid (mist, vapors, etc)	77.8	mmBtu/hr	0.0132	LB/HR		Use of Natural Gas
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Sulfuric Acid (mist, vapors, etc)	111.9	mmBtu/hr	0.02	LB/HR		Use of Natural Gas

Table D-4.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	59.61	TONS/MMCF	3-HR AVG	
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Carbon Dioxide Equivalent (CO_2e)	17.5	MMBTU/H	34189	T/YR	12 MONTH ROLLING TOTAL	
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Carbon Dioxide Equivalent (CO_2e)	24.59	MMBTU/H	34189	T/YR	12 MONTH ROLLING TOTAL	
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Carbon Dioxide Equivalent (CO_2e)	90.5	MMBtu/hr	46416	TPY		
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	50.4	MMBTU/hr	121	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	15	MMBTU/hr each	121	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Carbon Dioxide Equivalent (CO_2e)	0		121	LB/MMBTU		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	117	LB/MMBTU		Good operating practices Minimum Boiler Efficiency
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	117	LB/MMBTU		Good operating practices Minimum Boiler Efficiency
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	This is one we completed in 2022 as a 30REOZK so please seek out the air registration approval to cite in the revised air registration and tank permit is attached to site in the revised tank permit application.	LB/MMBTU		Good operating practices
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Auxiliary Boiler, 99.8 MMBtu/hr	03/09/2016	Carbon Dioxide Equivalent (CO_2e)	99.8	MMBtu/hr	0			Use of natural gas only
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	96	mmBtu/hr	22500	TON/YR	12-MONTH ROLLING AVERAGE	Good combustion practice
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	96	mmBtu/hr	11250	TONS/YEAR	12-MONTH ROLLING AVERAGE	Good combustion practice

Table D-4.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	80	mmBtu/hour	5059	TONS/YEAR	12 MONTH ROLLING	Good combustion practices.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	50	MMBtu/hr	117.1	LB/MMBTU		energy efficiency measures and only pipeline quality natural gas fuel shall be combusted
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	96	MMBtu per hour	11244	TONS PER YEAR		
*IN-0371	WABASH VALLEY RESOURCES, LLC	Auxiliary Boiler (AB-3)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	20	MMBtu/hr	117	LB/MMBTU		Good Combustion Practices
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	18.6	MMBTU/HR	9521.5	TONS PER YEAR	12-MONTH ROLLING AVERAGE BASIS	
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	50.4	MMBtu/hr	26125	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	18	MMBtu/hr, each	12675	TONS/YR	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	94	mm btu/h	455475	T/YR		Use of natural gas or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	80	mm BTU/h	117	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63 Subpart DDDDD.
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Carbon Dioxide Equivalent (CO_2e)	6	MMBTU/H	6155	T/YR	12-MO ROLLING TIME PERIOD	Use of pipeline quality natural gas and energy efficiency measures.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	83.5	MMBTU/H	43283	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Carbon Dioxide Equivalent (CO_2e)	3	MMBTU/H	7324	T/YR	COMBINED FOR ALL BOILERS	Use of pipeline quality natural gas and energy efficiency measures.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).

Table D-4.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/h	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	99.9	MMBTU/H	25623	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures, use of natural gas.
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	99	MMBTU/H	50776	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	80	MMBTU/H	41031	T/YR	12-MO ROLLING TIME PERIOD; EACH BOILER	Energy efficiency
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	25644	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy Efficiency Measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	25644	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Carbon Dioxide Equivalent (CO_2e)	60	MMBTU/H	119	LB/MMBTU	12 MO	good combustion practiced and pipeline quality natural gas
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	34	MMBTU/H	4008	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls/natural gas combustion
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	99	MMBTU/H	32171	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls, natural gas combustion, and ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	37.8	MMBTU/H	4456	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls/natural gas combustion
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	37.8	MMBTU/H	4502	T/YR	PER ROLLING 12 MONTH PERIOD	use of natural gas, good combustion controls
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	26.8	MMBTU/H	7845	T/YR	PER ROLLING 12 MONTH PERIOD	Natural gas as the sole fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	44.55	MMBTU/H	2817.6	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion practices and pipeline quality natural gas

Table D-4.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	80	MMBTU/H	5009.1	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion practices and pipeline quality natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	15.17	MMBTU/H	1784	LB/H		Good combustion practices and the use of natural gas
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	13.31	MMBtu/hr	44107	TON	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	55.4	MMBtu/hr	13561	TPY	12-MONTH ROLLING BASIS	
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Dioxide Equivalent (CO_2e)	95.7	MMBTU/H	119195	T/YR		Good combustion practices and use of low carbon fuel
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Dioxide Equivalent (CO_2e)	13.2	MMBTU/H	6850	T/YR		Good combustion practice to ensure complete combustion.
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Carbon Dioxide Equivalent (CO_2e)	76.6	MMBtu/hr	117.1	LB	MMBTU	
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	Natural gas-fied boiler (Boiler B01)	09/06/2018	Carbon Dioxide Equivalent (CO_2e)	35	mmBtu/hr	160	LBCO2E/1000 LB STEAM		Good combustion practices, use only natural gas, equip with Low NOx burners and flue gas recirculation
WI-0283	AFE, INC. LCM PLANT	B01-B12, Boilers	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	28	mmBTU/hr	160	LB/1000 LB CO2E	12-MONTH AVERAGE	Ultra-low NOx Burners, Flue Gas Recirculation, Good Combustion Practices and the Use of Pipeline Quality Natural Gas
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	28	mmBTU	160	LB CO2E/1000LB STEAM	12 MONTH AVERAGE	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices and the Use of Pipeline Quality Natural Gas.
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	8.5	MMBtu/H	90	% AVG THERM EFF		Use only natural gas.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	100	MMBTU/H	160	LB/MMBTU	12-MONTH ROLLING AVG.	Ultra-low NOx burners and flue gas recirculation. Operate and maintain boiler according to manufacturer's recommendations. Only use pipeline quality natural gas.
WI-0303	GREEN BAY PACKAGING INC.- GB MILL DIV.	Natural Gas-Fired Boiler (B01)	07/14/2020	Carbon Dioxide Equivalent (CO_2e)	32.7	MMBTU/H	16771	T/Y	ANY CONSECUTIVE 12-MONTH PERIOD	Only burn natural gas, good combustion practices, low NOx burner, and flue gas recirculation.
WI-0305	WPL- RIVERSIDE ENERGY CENTER	Natural Gas Auxiliary Boiler (B22)	01/22/2021	Carbon Dioxide Equivalent (CO_2e)	83.5	MMBTU/H	157	LB CO2/MMBTU	ANY MONTH, AVG ANY CONSECUTIVE 12-MONTHS	Combust only pipeline quality natural gas.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Carbon Dioxide Equivalent (CO_2e)	14.67	MMBTU/H	118	LB CO2/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas.

Table D-4.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Carbon Dioxide Equivalent (CO_2e)	77.8	mmBtu/hr	9107	LB/HR		Use of Natural Gas
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Carbon Dioxide Equivalent (CO_2e)	8.72	mmBtu/hr	0			Limited to natural gas; and tune-up the boiler once every five years.
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Carbon Dioxide Equivalent (CO_2e)	111.9	mmBtu/hr	14768	LB/HR		Use of Natural Gas

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Nitrogen Oxides (NO_x)	45.2	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Nitrogen Oxides (NO_x)	69	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Nitrogen Oxides (NO_x)	40	MMBtu/hr, total	100	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Nitrogen Oxides (NO_x)	40	MMBTU/H	0.036	LB/MMBTU		Low NOx burners
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Nitrogen Oxides (NO_x)	58	MMBtu/hr	0.1	LB/MMBTU		Low NOx burners SCR Combustion of clean fuel Good Combustion Practices
*IN-0371	WABASH VALLEY RESOURCES, LLC	Dewpoint Heater	01/11/2024	Nitrogen Oxides (NO_x)	1.44	MMBtu/hr	50	LB/MMSCF		Low NOx burners and good combustion practices
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Nitrogen Oxides (NO_x)	37	MMBtu/hr, each	181.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.18 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Nitrogen Oxides (NO_x)	17.5	MMBtu/hr, each	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Nitrogen Oxides (NO_x)	54	MMBtu/hr	158	LB/MMSCF	FLAMELESS MODE	Low-Nox Burner (Designed to maintain 0.15 lb/MMBtu in flameless mode and 0.25 lb/MMBtu in flame mode); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Nitrogen Oxides (NO_x)	48	MMBtu/hr	70	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Nitrogen Oxides (NO_x)	28	MMBtu/hr, each	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A &; B	07/23/2020	Nitrogen Oxides (NO_x)	60	MMBtu/hr, combined	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Nitrogen Oxides (NO_x)	40	MMBtu/hr, combined	70	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Nitrogen Oxides (NO_x)	53	MMBtu/hr (total)	5.3	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Nitrogen Oxides (NO_x)	3	MMBtu/hr (total)	0.3	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Nitrogen Oxides (NO_x)	19.2	MMBtu/hr (total)	1.92	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Nitrogen Oxides (NO_x)	3.7	MMBTU/H	0.55	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Nitrogen Oxides (NO_x)	20.8	MMBTU/H	0.75	LB/H	HOURLY	Low NOx burner
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Nitrogen Oxides (NO_x)	3.8	MMBTU/H	0.14	LB/H	HOURLY	Low NOx burner
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Nitrogen Oxides (NO_x)	34	MMBTU/H	0.05	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Low NOx burners and good design and combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Nitrogen Oxides (NO_x)	38	MMBTU/H	0.05	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices, Low NOx burners.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Nitrogen Oxides (NO_x)	25	MMBTU/H	0.05	LB/MMBTU	HOURLY; EACH HEATER	Low NOx burners and good combustion practices.

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Nitrogen Oxides (NO_x)	27	MMBTU/H	1.32	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Nitrogen Oxides (NO_x)	27	MMBTU/H	2.65	LB/H	HOURLY; EACH UNIT	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Nitrogen Oxides (NO_x)	7	MMBTU/H	0.036	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices and low NOx burners
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Nitrogen Oxides (NO_x)	15	MMBTU/H	0.3	LB/H		Low-NOx gas burner
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Nitrogen Oxides (NO_x)	0		0.0032	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Nitrogen Oxides (NO_x)	23	MMBtu/hr	50	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also required to be equipped with low-NOx burners (0.07 lb/MMBtu).
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Nitrogen Oxides (NO_x)	4.8	MMBtu/hr, each	50	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with low-NOx burners.
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Nitrogen Oxides (NO_x)	150.5	MMBtu/hr	0.035	LB/MMBTU		SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Nitrogen Oxides (NO_x)	94	MMBtu/hr	7.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks.

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Nitrogen Oxides (NO_x)	36	MMBtu/hr	7.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Nitrogen Oxides (NO_x)	3	MMBtu/hr	70	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with a low-NOx burner.
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Nitrogen Oxides (NO_x)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Nitrogen Oxides (NO_x)	65.5	MMBtu/hr	70	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low NOx burners (0.07 lb/MMBtu).
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Nitrogen Oxides (NO_x)	3	MMBTU/H	0.1	LB/MMBTU	1 HOUR	
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Nitrogen Oxides (NO_x)	0		0.01	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation.
TX-0845	ARKEMA BEAUMONT PLANT	HEATERS	08/24/2018	Nitrogen Oxides (NO_x)	31	BTU/HR	0.04	LB/MMBTU		LOW NOX BURNERS, CLEAN FUEL
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Nitrogen Oxides (NO_x)	100	MMBtu	0.04	LB/MMBTU		Low NOx burners and good combustion practice.
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Nitrogen Oxides (NO_x)	0		9	PPMVD		LOW NOX BURNERS

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Nitrogen Oxides (NO_x)	0		0.1	LB/MMBTU		Natural Gas Fuel
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Nitrogen Oxides (NO_x)	0		0.014	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation with a SCR system to further reduce NOx.
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Nitrogen Oxides (NO_x)	16.13	mm btu/hr	0			ULNB and Good Combustion Practices
*LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Nitrogen Oxides (NO_x)	90	mm btu/hr	0.01	LB/MM BTU	ANNUAL	Ultra-low NOx burners
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Nitrogen Oxides (NO_x)	0		0.06	LB/MMBTU		LNB
TX-0755	RAMSEY GAS PLANT	Hot Oil Heaters and Regeneration Heaters	05/21/2015	Nitrogen Oxides (NO_x)	60	MMBTU/H	0.045	LB/MMBTU		low NOx burners
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Nitrogen Oxides (NO_x)	5.12	MMBtu/hr	50	LB/MMSCF		low NOx burners, good combustion practices and only pipeline quality natural gas shall be combusted
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Nitrogen Oxides (NO_x)	75	MMBtu/hr	0.1	LB/MMBTU		Low NOx burners Combustion of clean fuel Good Combustion Practices
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Nitrogen Oxides (NO_x)	2	mmBTU/hr	0.2	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Nitrogen Oxides (NO_x)	15	MMBTU/H	2.12	LB/H		Good combustion practices and the use of natural gas
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Nitrogen Oxides (NO_x)	1.5	mmBTU/hr	0.1	LB/MMBTU		Good Combustion Practices

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Nitrogen Oxides (NO_x)	78.2	MMBTU/HR	0.035	LB/MMBTU		SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND GOOD COMBUSTION PRACTICES
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND GOOD COMBUSTION PRACTICES
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Nitrogen Oxides (NO_x)	7.37	mm btu/hr	0			good combustion practices
AR-0167	LION OIL COMPANY	SN-803 - #4 Pre-Flash Column Reboiler	12/01/2020	Nitrogen Oxides (NO_x)	40	MMBtu/hr	1.9	LB/HR	3-HOUR AVERAGE	Ultra-low NOx burners and good combustion practice
AR-0167	LION OIL COMPANY	SN-808 - #7 FCCU Furnace	12/01/2020	Nitrogen Oxides (NO_x)	56	MMBtu/hr	2.8	LB/HR	3-HOUR AVERAGE	Good combustion practice
AR-0167	LION OIL COMPANY	SN-810 - #9 Hydrotreater Furnace/Reboiler	12/01/2020	Nitrogen Oxides (NO_x)	70	MMBtu/hr	12.7	LB/HR	3-HOUR AVERAGE	
AR-0167	LION OIL COMPANY	SN-842 - #12 Unit Distillate Hydrotreater	12/01/2020	Nitrogen Oxides (NO_x)	50	MMBtu/hr	5.3	LB/HR	3-HOUR AVERAGE	Good combustion practice
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Nitrogen Oxides (NO_x)	0		0.05	LB/MMBTU	UNITS 1-6, COMBUSTING NATURAL GAS	
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Nitrogen Oxides (NO_x)	47.7	mmBtu/hr	0.07	LB/MMBTU	3-HR AVG	LNB, good burner design, and GCP
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Nitrogen Oxides (NO_x)	100	MMBTU/H	10	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Nitrogen Oxides (NO_x)	70	MMBTU/HR	12.611	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Nitrogen Oxides (NO_x)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices

Table D-5.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Nitrogen Oxides (NO_x)	38	MMBTU/H	0.05	LB/MMBTU	HOURLY	Good design and combustion practices, low NOx burners
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.011	LB/MMBTU	3 HOUR AVG	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Nitrogen Oxides (NO_x)	88	MMBTU/H	6.16	LB/H		Use of natural gas, use of low NOx burners, good combustion practices and design
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Nitrogen Oxides (NO_x)	32	MMBtu/hr	0.036	LB/MMBTU	3-HOUR AVERAGE	Low NOx Burners, Good Combustion Practices, Limited Operation of 500 hours per year per heater.
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Two natural gas heaters	03/09/2016	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.1	LB/MMBTU		Must have NOx emission design value less than 0.1 lb/MMBtu
FL-0363	DANIA BEACH ENERGY CENTER	Two natural gas heaters	12/04/2017	Nitrogen Oxides (NO_x)	9.9	MMBtu/hr	0.1	LB/MMBTU	DESIGN VALUE	Manufacturer certification
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Nitrogen Oxides (NO_x)	0		0			good engineering design and practices and use of clean fuels

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Carbon Monoxide	45.2	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Carbon Monoxide	69	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Carbon Monoxide	40	MMBtu/hr, total	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Carbon Monoxide	40	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practice to ensure complete combustion.
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Carbon Monoxide	58	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Carbon Monoxide	37	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Carbon Monoxide	17.5	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Carbon Monoxide	54	MMBtu/hr	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Carbon Monoxide	48	MMBtu/hr	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Carbon Monoxide	28	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Carbon Monoxide	60	MMBtu/hr, combined	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Carbon Monoxide	40	MMBtu/hr, combined	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Carbon Monoxide	53	MMBtu/hr (total)	4.45	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Monoxide	3	MMBtu/hr (total)	0.25	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Monoxide	19.2	MMBtu/hr (total)	1.61	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Carbon Monoxide	3.7	MMBTU/H	0.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Carbon Monoxide	20.8	MMBTU/H	0.77	LB/H	HOURLY	Good combustion controls.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Carbon Monoxide	3.8	MMBTU/H	0.14	LB/H	HOURLY	Good combustion controls
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Carbon Monoxide	34	MMBTU/H	0.082	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good design and operation
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Carbon Monoxide	38	MMBTU/H	0.082	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and operation.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Carbon Monoxide	25	MMBTU/H	0.08	LB/MMBTU	HOURLY; EACH HEATER	Good combustion practices.
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Carbon Monoxide	27	MMBTU/H	1.11	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Carbon Monoxide	27	MMBTU/H	2.22	LB/H	HOURLY; EACH UNIT	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Carbon Monoxide	7	MMBTU/H	0.037	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Carbon Monoxide	15	MMBTU/H	0.83	LB/H		Combustion control
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Carbon Monoxide	0		0.08	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Carbon Monoxide	23	MMBtu/hr	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Carbon Monoxide	4.8	MMBtu/hr, each	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Carbon Monoxide	150.5	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Carbon Monoxide	94	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Carbon Monoxide	36	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Carbon Monoxide	3	MMBtu/hr	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Carbon Monoxide	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Carbon Monoxide	65.5	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Carbon Monoxide	3	MMBTU/H	0.04	LB/MMBTU	1 HOUR	
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Carbon Monoxide	100	MMBtu	50	PPMVD	3% O2	Good combustion practice and proper design.
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Carbon Monoxide	0		50	PPMVD	3% O2	Good combustion practices and fire hydrogen-rich plant fuel gas
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Carbon Monoxide	0		0.084	LB/MMBTU		Natural Gas Fuel.
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Carbon Monoxide	16.13	mm btu/hr	0			Good Combustion Practices
*LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Carbon Monoxide	90	mm btu/hr	0.037	LB/MM BTU	ANNUAL	Proper burner design and operations Good combustion practices Compliance with 40 CFR 63 Subpart DDDDD
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Carbon Monoxide	0		0.037	LB/MMBTU		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
TX-0755	RAMSEY GAS PLANT	Hot Oil Heaters and Regeneration Heaters	05/21/2015	Carbon Monoxide	60	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practices and firing of residue gas with low carbon content
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Carbon Monoxide	5.12	MMBtu/hr	84	LB/MMSCF		good combustion practices
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Carbon Monoxide	75	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Carbon Monoxide	2	mmBTU/hr	0.16	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
OH-0383	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	07/17/2020	Carbon Monoxide	15	MMBTU/H	0.521	LB/H		Good combustion practices and the use of natural gas
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Carbon Monoxide	1.5	mmBTU/hr	0.082	LB/MMBTU		Good Combustion Practices
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Carbon Monoxide	78.2	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Carbon Monoxide	7.37	mm btu/hr	0			good combustion practices
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Carbon Monoxide	0		0.038	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Carbon Monoxide	47.7	mmBtu/hr	0.0194	LB/MMBTU	3-HR AVG	GCP and good burner design
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Carbon Monoxide	100	MMBTU/H	8.24	LB/H		good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Carbon Monoxide	70	MMBTU/HR	2.556	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Carbon Monoxide	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Carbon Monoxide	38	MMBTU/H	0.082	LB/MMBTU	HOURLY	Good design and operation

Table D-5.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Carbon Monoxide	10	MMBtu/hr	0.08	LB/MMBTU	3 HOUR AVG	
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Carbon Monoxide	88	MMBTU/H	6.16	LB/H		Use natural gas, use of baffle type burners, good combustion practices and design
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Carbon Monoxide	32	MMBtu/hr	0.087	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Carbon Monoxide	16.8	MMBTU/HR	50	PPMVD	3% O2	Good combustion practices
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Carbon Monoxide	0		0			good engineering design and practices and use of clean fuels

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Volatile Organic Compounds (VOC)	45.2	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Volatile Organic Compounds (VOC)	69	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Volatile Organic Compounds (VOC)	40	MMBtu/hr, total	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Volatile Organic Compounds (VOC)	40	MMBTU/H	0.94	T/YR		Good combustion practice to ensure complete combustion.
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Volatile Organic Compounds (VOC)	58	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Volatile Organic Compounds (VOC)	37	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Volatile Organic Compounds (VOC)	17.5	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Volatile Organic Compounds (VOC)	54	MMBtu/hr	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Volatile Organic Compounds (VOC)	48	MMBtu/hr	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Volatile Organic Compounds (VOC)	28	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Volatile Organic Compounds (VOC)	60	MMBtu/hr, combined	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Volatile Organic Compounds (VOC)	40	MMBtu/hr, combined	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Volatile Organic Compounds (VOC)	53	MMBtu/hr (total)	0.29	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Volatile Organic Compounds (VOC)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Volatile Organic Compounds (VOC)	19.2	MMBtu/hr (total)	0.11	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Volatile Organic Compounds (VOC)	3.7	MMBTU/H	0.03	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Volatile Organic Compounds (VOC)	20.8	MMBTU/H	0.17	LB/H	HOURLY	Good combustion controls
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Volatile Organic Compounds (VOC)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Good combustion controls.
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Volatile Organic Compounds (VOC)	34	MMBTU/H	0.0054	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and operating/combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Volatile Organic Compounds (VOC)	38	MMBTU/H	0.0054	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and operating/combustion practices.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Volatile Organic Compounds (VOC)	25	MMBTU/H	0.005	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Volatile Organic Compounds (VOC)	27	MMBTU/H	0.07	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Volatile Organic Compounds (VOC)	27	MMBTU/H	0.15	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Volatile Organic Compounds (VOC)	7	MMBTU/H	0.025	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Volatile Organic Compounds (VOC)	15	MMBTU/H	0.075	LB/H		Combustion control
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Volatile Organic Compounds (VOC)	0		0.01	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Volatile Organic Compounds (VOC)	23	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Volatile Organic Compounds (VOC)	4.8	MMBtu/hr, each	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Volatile Organic Compounds (VOC)	150.5	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Volatile Organic Compounds (VOC)	94	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Volatile Organic Compounds (VOC)	36	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Volatile Organic Compounds (VOC)	3	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Volatile Organic Compounds (VOC)	65.5	MMBtu/hr	5.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for good combustion efficiency
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Volatile Organic Compounds (VOC)	100	MMBtu	0.0054	LB/MMBTU		Good combustion practice and proper design.
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Volatile Organic Compounds (VOC)	0		0.0055	LB/MMBTU		Natural Gas Fuel.
OK-0164	MIDWEST CITY AIR DEPOT	Heaters/Boilers	01/08/2015	Volatile Organic Compounds (VOC)	0	MMBTUH	7.1	TONS PER YEAR	TOTAL FOR ALL UNITS.	1. Use pipeline-quality natural gas. 2. Good Combustion Practices w/emission rate limit of 0.005 lb/MMBTU based on AP-42 (7/1998).

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0127	WINPAK HEAT SEAL CORPORATION	Heating Units	10/05/2018	Volatile Organic Compounds (VOC)	1	mmBtu/hr	0			Units shall be operated in accordance with good combustion practices.
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for high efficiency combustion.
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Volatile Organic Compounds (VOC)	16.13	mm btu/hr	0.0054	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas
*LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Volatile Organic Compounds (VOC)	90	mm btu/hr	0.0054	LB/MM BTU	ANNUAL	Proper burner design and operations Good combustion practices Compliance with 40 CFR 63 Subpart DDDDD
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Volatile Organic Compounds (VOC)	0		4.02	LB/H		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Volatile Organic Compounds (VOC)	5.12	MMBtu/hr	5.5	LB/MMSCF		good combustion practices

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Volatile Organic Compounds (VOC)	75	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Volatile Organic Compounds (VOC)	2	mmBTU/hr	0.011	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
TX-0877	SWEENY REFINERY	Isostripper Reboiler (heater)	01/08/2020	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Good combustion practices, use of natural gas fuel for the project heater
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Volatile Organic Compounds (VOC)	8.5	MMBtu/H	0.0055	LB/MMBTU		
WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	P44 Space Heaters	04/01/2019	Volatile Organic Compounds (VOC)	20	mmBTU/hr	0.0055	LB/MMBTU		Good Combustion Practices, the Use of Low-NOx Burners
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Volatile Organic Compounds (VOC)	78.2	MMBTU/HR	0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Volatile Organic Compounds (VOC)	7.37	mm btu/hr	0			good combustion practices
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Volatile Organic Compounds (VOC)	0		0.0053	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Volatile Organic Compounds (VOC)	47.7	mmBtu/hr	0.0014	LB/MMBTU	3-HR AVG	GCP and good burner design
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Volatile Organic Compounds (VOC)	100	MMBTU/H	0.54	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Volatile Organic Compounds (VOC)	70	MMBTU/HR	0.378	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Volatile Organic Compounds (VOC)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, good combustion practices
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Volatile Organic Compounds (VOC)	1.83	MMBTU/H	0.01	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Volatile Organic Compounds (VOC)	38	MMBTU/H	0.0054	LB/MMBTU	HOURLY	Good design and operating/combustion practices
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Volatile Organic Compounds (VOC)	88	MMBTU/H	0.48	LB/H		Use of natural gas, good combustion practices and design
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Volatile Organic Compounds (VOC)	32	MMBtu/hr	0.0057	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
FL-0364	SEMINOLE GENERATING STATION	Two natural gas heaters (< 10 MMBtu/hr each)	03/21/2018	Volatile Organic Compounds (VOC)	9.9	MMBtu/hr	0.005	LB/MMBTU		

Table D-5.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Volatile Organic Compounds (VOC)	16.8	MMBTU/HR	0.005	LB/MMBTU		Good combustion practices

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, filterable (FPM)	40	MMBtu/hr, total	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, filterable (FPM)	37	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, filterable (FPM)	17.5	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, filterable (FPM)	54	MMBtu/hr	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, filterable (FPM)	48	MMBtu/hr	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, filterable (FPM)	28	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, filterable (FPM)	60	MMBtu/hr, combined	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, filterable (FPM)	40	MMBtu/hr, combined	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, filterable (FPM)	53	MMBtu/hr (total)	0.1	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, filterable (FPM)	3	MMBtu/hr (total)	0.006	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems & 1 MMBtu	07/25/2022	Particulate matter, filterable (FPM)	19.2	MMBtu/hr (total)	0.04	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, filterable (FPM)	3.7	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, filterable (FPM)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, filterable (FPM)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, filterable (FPM)	34	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, filterable (FPM)	38	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, filterable (FPM)	25	MMBTU/H	0.002	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, filterable (FPM)	27	MMBTU/H	0.002	LB/MMBTU	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, filterable (FPM)	27	MMBTU/H	0.002	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, filterable (FPM)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, filterable (FPM)	23	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, filterable (FPM)	4.8	MMBtu/hr, each	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, filterable (FPM)	94	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, filterable (FPM)	36	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, filterable (FPM)	3	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, filterable (FPM)	65.5	MMBtu/hr	1.9	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Particulate matter, filterable (FPM)	100	MMBtu	0.0075	LB/MMBTU		Good combustion practice, clean fuel, and proper design.

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Particulate matter, filterable (FPM)	0		0			Good combustion practices and fire hydrogen□h plant fuel gas, 5% OPACITY
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, filterable (FPM)	5.12	MMBtu/hr	1.9	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, filterable (FPM)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Particulate matter, filterable (FPM)	78.2	MMBTU/HR	0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, filterable (FPM)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, filterable (FPM)	70	MMBTU/HR	0.13	LB/H	3HR AVERAGE	GOOD COMBUSTION PRACTICE
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, filterable (FPM)	38	MMBTU/H	0.0075	LB/MMBTU	HOURLY	Good combustion practices
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Particulate matter, filterable (FPM)	16.8	MMBTU/HR	0.007	LB/MMBTU		Good combustion practices

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Particulate matter, total (TPM10)	45.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Particulate matter, total (TPM2.5)	45.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Particulate matter, total (TPM10)	69	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Particulate matter, total (TPM2.5)	69	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, total (TPM10)	40	MMBtu/hr, total	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, total (TPM2.5)	40	MMBtu/hr, total	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Particulate matter, total (TPM10)	40	MMBTU/H	1.31	T/YR		Good combustion practice to ensure complete combustion. gaseous fuel
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Particulate matter, total < 2.5 Âµ (TPM2.5)	40	MMBTU/H	1.31	T/YR		Good combustion practice to ensure complete combustion. gaseous fuel
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Particulate matter, total (TPM10)	58	MMBtu/hr	0.013	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Particulate matter, total (TPM2.5)	58	MMBtu/hr	0.013	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, total (TPM10)	37	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, total (TPM2.5)	37	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, total (TPM10)	17.5	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, total (TPM2.5)	17.5	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, total (TPM10)	54	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, total (TPM2.5)	54	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, total (TPM10)	48	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, total (TPM2.5)	48	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, total (TPM10)	28	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, total (TPM2.5)	28	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, total (TPM10)	60	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, total (TPM2.5)	60	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, total (TPM10)	40	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, total (TPM2.5)	40	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, total (TPM10)	53	MMBtu/hr (total)	0.4	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, total (TPM2.5)	53	MMBtu/hr (total)	0.4	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total < 10 Âµ (TPM10)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM2.5)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total < 10 Âµ (TPM10)	19.2	MMBtu/hr (total)	0.15	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM2.5)	19.2	MMBtu/hr (total)	0.15	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM10)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM2.5)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM10)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM2.5)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM10)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM2.5)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, total (TPM10)	34	MMBTU/H	0.0005	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, total (TPM2.5)	34	MMBTU/H	0.0004	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, total (TPM10)	38	MMBTU/H	0.0005	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, total (TPM2.5)	38	MMBTU/H	0.0004	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, total (TPM10)	25	MMBTU/H	0.008	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, total (TPM2.5)	25	MMBTU/H	0.008	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, total (TPM10)	27	MMBTU/H	0.1	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, total (TPM2.5)	27	MMBTU/H	0.1	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, total (TPM10)	27	MMBTU/H	0.2	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, total (TPM2.5)	27	MMBTU/H	0.2	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM10)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion)
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM2.5)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Particulate matter, total (TPM10)	15	MMBTU/H	0.075	LB/H		Combustion control
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Particulate matter, total (TPM2.5)	15	MMBTU/H	0.075	LB/H		Combustion control
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM10)	0		0.0079	GR/DSCF		Dust Collector and Scrubber

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM2.5)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, total (TPM10)	23	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, total (TPM2.5)	23	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM10)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM2.5)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Particulate matter, total (TPM10)	150.5	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Particulate matter, total (TPM2.5)	150.5	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, total (TPM10)	94	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, total (TPM2.5)	94	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, total (TPM10)	36	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, total (TPM2.5)	36	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM10)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM2.5)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Particulate matter, total (TPM10)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Particulate matter, total (TPM2.5)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, total < 10 Âµ (TPM10)	65.5	MMBtu/hr	7.6	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, total (TPM2.5)	65.5	MMBtu/hr	7.6	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Particulate matter, total (TPM2.5)	3	MMBTU/H	0			

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM10)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM2.5)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Particulate matter, total (TPM2.5)	16.13	mm btu/hr	0.0075	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Particulate matter, total (TPM10)	16.13	mm btu/hr	0.0075	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas
*LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Particulate matter, total (TPM10)	90	mm btu/hr	0.0075	LB/MM BTU		Proper burner design and operations□ Good combustion practices□ Compliance with 40 CFR 63 Subpart
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM10)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM2.5)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM10)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM2.5)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, total (TPM10)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, total (TPM2.5)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM10)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM2.5)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Particulate matter, total (TPM10)	15	MMBTU/H	0.112	LB/H		Good combustion practices and the use of natural gas
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Particulate matter, total (TPM2.5)	15	MMBTU/H	0.112	LB/H		Good combustion practices and the use of natural gas
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Particulate matter, total (TPM2.5)	78.2	MMBTU/HR	0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM10)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM10)	7.37	mm btu/hr	0			good combustion practices
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM2.5)	7.37	mm btu/hr	0			good combustion practices
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Particulate matter, total (TPM10)	47.7	mmBtu/hr	0.0024	LB/MMBTU	3-HR AVG	GCP and good burner design
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Particulate matter, total (TPM2.5)	47.7	mmBtu/hr	0.0024	LB/MMBTU	3-HR AVG	GCP and good burner design
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Particulate matter, total (TPM10)	100	MMBTU/H	0.75	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Particulate matter, total (TPM2.5)	100	MMBTU/H	0.75	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, total (TPM10)	70	MMBTU/HR	0.522	LB/H	3HOUR AVERAGE	GOOD COMBUSTION PRACTICES

Table D-5.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, total (TPM2.5)	70	MMBTU/HR	0.522	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Particulate matter, total (TPM10)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Particulate matter, total (TPM2.5)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM10)	1.83	MMBTU/H	0.01	LB/H		USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM2.5)	1.83	MMBTU/H	0.003	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, total (TPM10)	38	MMBTU/H	0.0005	LB/MMBTU	HOURLY	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, total (TPM2.5)	38	MMBTU/H	0.0004	LB/MMBTU	HOURLY	Good combustion practices
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Particulate matter, total (TPM10)	88	MMBTU/H	0.88	LB/H		Use of natural gas, good combustion practices and design
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Particulate matter, total (TPM2.5)	88	MMBTU/H	0.88	LB/H		Use of natural gas, good combustion practices and design
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Particulate matter, total (TPM10)	32	MMBtu/hr	0.0079	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Particulate matter, total (TPM2.5)	32	MMBtu/hr	0.0079	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM10)	0		0			good engineering design and practices and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM2.5)	0		0			good engineering design and practices and use of clean fuels

Table D-5.6 Summary of H_2SO_4 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Sulfuric Acid (mist, vapors, etc)	20.8	MMBTU/H	0.34	GR S/100 SCF	FUEL SUPPLIER RECORDS	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Sulfuric Acid (mist, vapors, etc)	3.8	MMBTU/H	0.34	GR S/100 SCF	FUEL SUPPLIER RECORDS	Low sulfur fuel
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Sulfuric Acid (mist, vapors, etc)	15	MMBTU/H	0.0035	LB/H		Pipeline natural gas fuel

Table D-5.7 Summary of CO_2e BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	40	MMBtu/hr, total	20734	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Carbon Dioxide Equivalent (CO_2e)	40	MMBTU/H	20758	T/YR		Good combustion practice to ensure complete combustion.
*IN-0371	WABASH VALLEY RESOURCES, LLC	Dewpoint Heater	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	1.44	MMBtu/hr	117	LB/MMBTU		Good Combustion Practices
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	37	MMBtu/hr, each	76717	TON/YR	12-MONTH ROLLING	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and meet design standards.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	17.5	MMBtu/hr, each	18142	TON/YR	12-MONTH ROLLING	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	54	MMBtu/hr	27991	TON/YR	12-MONTH ROLLING	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and implement design standards.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	48	MMBtu/hr	24881	TON/YR	12-MONTH ROLLING	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and meet design requirements.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	28	MMBtu/hr, each	43542	TON/YR	12-MONTH ROLLING, COMBINED	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and meet design requirements.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	60	MMBtu/hr, combined	31101	TON/YR	12-MONTH ROLLING, COMBINED	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and meet design requirements.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	40	MMBtu/hr, combined	20734	TON/YR	12-MONTH ROLLING, COMBINED	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan and meet design requirements.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Carbon Dioxide Equivalent (CO_2e)	53	MMBtu/hr (total)	27890	TONS/YR	12-MONTH ROLLING TOTAL	Design Requirements, Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Dioxide Equivalent (CO_2e)	3	MMBtu/hr (total)	1579	TONS/YR	12-MONTH ROLLING TOTAL	Design Requirements, Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Dioxide Equivalent (CO_2e)	19.2	MMBtu/hr (total)	10104	TONS/YR	12-MONTH ROLLING TOTAL	Design Requirements, Good Combustion & Operation Practices (GCOP) Plan

Table D-5.7 Summary of CO_2e BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	3.7	MMBTU/H	1934	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	20.8	MMBTU/H	6310	T/YR	12-MO ROLLING TIME PERIOD	Natural gas fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	3.8	MMBTU/H	6310	T/YR	12-MONTH ROLLING TIME PERIOD	Natural gas fuel
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Carbon Dioxide Equivalent (CO_2e)	34	MMBTU/H	17438	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	Good combustion and maintenance practices, natural gas only.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	38	MMBTU/H	19490	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and maintenance practices, natural gas only.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Carbon Dioxide Equivalent (CO_2e)	25	MMBTU/H	12822	T/YR	12-MO ROLLING TIME PERIOD; EACH UNIT	Utilize low-carbon fuels and implement energy efficiency measures and preventative maintenance pursuant to manufacturer recommendations.
*MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Carbon Dioxide Equivalent (CO_2e)	27	MMBTU/H	13848	T/YR	12-MO ROLLING TIME PERIOD	Energy Efficiency Measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Carbon Dioxide Equivalent (CO_2e)	27	MMBTU/H	13848	T/YR	12-MO ROLLING TIME PERIOD; COMBINED LIMI	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	7	MMBTU/H	3590	T/YR	12-MO ROLLING TIME PERIOD; EACH UNIT	Energy efficiency
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Carbon Dioxide Equivalent (CO_2e)	15	MMBTU/H	7695	T/YR	PER ROLLING 12 MONTH PERIOD	Natural gas, low-emitting fuel
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		54701	TPY		Good Operating Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	23	MMBtu/hr	11922	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	4.8	MMBtu/hr, each	37581	TONS/YR	12-MONTH ROLLING, COMBINED	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	94	MMBtu/hr	48725	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.

Table D-5.7 Summary of CO_2e BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	36	MMBtu/hr	18660	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	3	MMBtu/hr	30	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Carbon Dioxide Equivalent (CO_2e)	23	MM BTU/hr (each)	0			good equipment design and good combustion practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	65.5	MMBtu/hr	33952	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
TX-0845	ARKEMA BEAUMONT PLANT	HEATERS	08/24/2018	Carbon Dioxide Equivalent (CO_2e)	31	BTU/HR	0			low carbon fuel selection, and good combustion practices
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Carbon Dioxide Equivalent (CO_2e)	100	MMBtu	0			Good combustion practice, clean fuel, and proper design
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			Good combustion practices and fire hydrogenâ€□rich plant □ fuel gas
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Carbon Dioxide Equivalent (CO_2e)	0		120	LB/MMBTU		Natural Gas Fuel
OK-0164	MIDWEST CITY AIR DEPOT	Heaters/Boilers	01/08/2015	Carbon Dioxide Equivalent (CO_2e)	0	MMBTUH	153716	TONS PER YEAR	TOTAL FOR ALL UNITS.	1. Use pipeline-quality natural gas.□ 2. Good Combustion Practices.□ 3. Tune-ups for applicable boilers/heaters per 40CFR63, Subpart DDDDD.
TX-0746	NUEVO MIDSTREAM, RAMSEY GAS PLANT	Hot Oil Heater	11/18/2014	Carbon Dioxide Equivalent (CO_2e)	60	MMBTU/H	280.5	LB CO2/MMSCFD PROCES	12-MONTH ROLLING AVERAGE WITH MSS	
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Carbon Dioxide Equivalent (CO_2e)	16.13	mm btu/hr	0			Use Low Carbon Fuel, Energy Efficiency Measures, and Good Combustion Practices
*LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Carbon Dioxide Equivalent (CO_2e)	90	mm btu/hr	0			Use of low carbon fuels□ Good combustion/operation/maintenance practices□ Efficient design

Table D-5.7 Summary of CO_2e BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		5858	TONS/YR		Use of fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	5.12	MMBtu/hr	2625	TONS/YR		good combustion practices and only pipeline quality natural gas shall be combusted
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	75	MMBtu/hr	117	LB/MMBTU		Good Operating Practices
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	15	MMBTU/H	1764	LB/H		Good combustion practices and the use of natural gas
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	8.5	MMBtu/H	90	% AVG THERM EFF		Use only natural gas.
WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	P44 Space Heaters	04/01/2019	Carbon Dioxide Equivalent (CO_2e)	20	mmBTU/hr	0			Good Combustion Practices, the Use of Low-NOx Burners
TX-0746	NUEVO MIDSTREAM, RAMSEY GAS PLANT	Regeneration Heater	11/18/2014	Carbon Dioxide Equivalent (CO_2e)	36	MMBTU/H	168.3	LB CO2/MMSCF	12-MONTH ROLLING WITH MSS	
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Carbon Dioxide Equivalent (CO_2e)	7.37	mm btu/hr	0			good combustion/operating/maintenance practices and fueled by natural gas
*IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Carbon Dioxide Equivalent (CO_2e)	47.7	mmBtu/hr	604	TONS/YEAR	12-MONTH ROLLING AVG	Energy efficient design, GCP, and use of automated combustion management system with inlet air controls
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Carbon Dioxide Equivalent (CO_2e)	100	MMBTU/H	2840	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Carbon Dioxide Equivalent (CO_2e)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	38	MMBTU/H	19490	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and maintenance practices, natural gas only.
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Carbon Dioxide Equivalent (CO_2e)	10	MMBtu/hr	117.1	LB/MMBTU		
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Carbon Dioxide Equivalent (CO_2e)	88	MMBTU/H	10283.06	LB/H		Use of natural gas and energy efficient design
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Carbon Dioxide Equivalent (CO_2e)	32	MMBtu/hr	117.1	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Carbon Dioxide Equivalent (CO_2e)	16.8	MMBTU/HR	0			Good combustion practices
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			good equipment design and good combustion practices

Table D-6.1 Summary of NO_x BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0371	WABASH VALLEY RESOURCES, LLC	Dewpoint Heater	01/11/2024	Nitrogen Oxides (NO_x)	1.44	MMBtu/hr	50	LB/MMSCF		Low NOx burners and good combustion practices
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Nitrogen Oxides (NO_x)	3	MMBtu/hr (total)	0.3	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Nitrogen Oxides (NO_x)	3.7	MMBTU/H	0.55	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Nitrogen Oxides (NO_x)	3.8	MMBTU/H	0.14	LB/H	HOURLY	Low NOx burner
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Nitrogen Oxides (NO_x)	7	MMBTU/H	0.036	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices and low NOx burners
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Nitrogen Oxides (NO_x)	0		0.0032	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Nitrogen Oxides (NO_x)	4.8	MMBtu/hr, each	50	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with low-NOx burners.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Nitrogen Oxides (NO_x)	3	MMBtu/hr	70	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with a low-NOx burner.
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Nitrogen Oxides (NO_x)	3	MMBTU/H	0.1	LB/MMBTU	1 HOUR	

Table D-6.1 Summary of NO_x BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Nitrogen Oxides (NO_x)	0		0.01	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation.
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Nitrogen Oxides (NO_x)	0		9	PPMVD		LOW NOX BURNERS
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Nitrogen Oxides (NO_x)	0		0.1	LB/MMBTU		Natural Gas Fuel
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Nitrogen Oxides (NO_x)	0		0.014	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation with a SCR system to further reduce NOx.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Nitrogen Oxides (NO_x)	0		0.06	LB/MMBTU		LNB
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Nitrogen Oxides (NO_x)	5.12	MMBtu/hr	50	LB/MMSCF		low NOx burners, good combustion practices and only pipeline quality natural gas shall be combusted
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Nitrogen Oxides (NO_x)	2	mmBTU/hr	0.2	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Nitrogen Oxides (NO_x)	1.5	mmBTU/hr	0.1	LB/MMBTU		Good Combustion Practices
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND GOOD COMBUSTION PRACTICES

Table D-6.1 Summary of NO_x BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Nitrogen Oxides (NO_x)	7.37	mm btu/hr	0			good combustion practices
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Nitrogen Oxides (NO_x)	0		0.05	LB/MMBTU	UNITS 1-6, COMBUSTING NATURAL GAS	
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.011	LB/MMBTU	3 HOUR AVG	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Two natural gas heaters	03/09/2016	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.1	LB/MMBTU		Must have NOx emission design value less than 0.1 lb/MMBtu
FL-0363	DANIA BEACH ENERGY CENTER	Two natural gas heaters	12/04/2017	Nitrogen Oxides (NO_x)	9.9	MMBtu/hr	0.1	LB/MMBTU	DESIGN VALUE	Manufacturer certification
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Nitrogen Oxides (NO_x)	0		0			good engineering design and practices and use of clean fuels

Table D-6.2 Summary of CO BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Monoxide	3	MMBtu/hr (total)	0.25	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Carbon Monoxide	3.7	MMBTU/H	0.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Carbon Monoxide	3.8	MMBTU/H	0.14	LB/H	HOURLY	Good combustion controls
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Carbon Monoxide	7	MMBTU/H	0.037	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Carbon Monoxide	0		0.08	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Carbon Monoxide	4.8	MMBtu/hr, each	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Carbon Monoxide	3	MMBtu/hr	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Carbon Monoxide	3	MMBTU/H	0.04	LB/MMBTU	1 HOUR	
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Carbon Monoxide	0		50	PPMVD	3% O2	Good combustion practices and fire hydrogen[illegible]ch plant fuel gas
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Carbon Monoxide	0		0.084	LB/MMBTU		Natural Gas Fuel.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Carbon Monoxide	0		0.037	LB/MMBTU		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Carbon Monoxide	5.12	MMBtu/hr	84	LB/MMSCF		good combustion practices

Table D-6.2 Summary of CO BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Carbon Monoxide	2	mmBTU/hr	0.16	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Carbon Monoxide	1.5	mmBTU/hr	0.082	LB/MMBTU		Good Combustion Practices
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Carbon Monoxide	7.37	mm btu/hr	0			good combustion practices
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Carbon Monoxide	0		0.038	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Carbon Monoxide	10	MMBtu/hr	0.08	LB/MMBTU	3 HOUR AVG	
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Carbon Monoxide	0		0			good engineering design and practices and use of clean fuels

Table D-6.3 Summary of VOC BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Volatile Organic Compounds (VOC)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Volatile Organic Compounds (VOC)	3.7	MMBTU/H	0.03	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Volatile Organic Compounds (VOC)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Good combustion controls.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Volatile Organic Compounds (VOC)	7	MMBTU/H	0.025	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Volatile Organic Compounds (VOC)	0		0.01	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Volatile Organic Compounds (VOC)	4.8	MMBtu/hr, each	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Volatile Organic Compounds (VOC)	3	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for good combustion efficiency
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Volatile Organic Compounds (VOC)	0		0.0055	LB/MMBTU		Natural Gas Fuel.
OK-0164	MIDWEST CITY AIR DEPOT	Heaters/Boilers	01/08/2015	Volatile Organic Compounds (VOC)	0	MMBTUH	7.1	TONS PER YEAR	TOTAL FOR ALL UNITS.	1. Use pipeline-quality natural gas. 2. Good Combustion Practices w/emission rate limit of 0.005 lb/MMBTU based on AP-42 (7/1998).
IL-0127	WINPAK HEAT SEAL CORPORATION	Heating Units	10/05/2018	Volatile Organic Compounds (VOC)	1	mmBtu/hr	0			Units shall be operated in accordance with good combustion practices.
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for high efficiency combustion.

Table D-6.3 Summary of VOC BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Volatile Organic Compounds (VOC)	0		4.02	LB/H		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Volatile Organic Compounds (VOC)	5.12	MMBtu/hr	5.5	LB/MMSCF		good combustion practices
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Volatile Organic Compounds (VOC)	2	mmBTU/hr	0.011	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
TX-0877	SWEENY REFINERY	Isostripper Reboiler (heater)	01/08/2020	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Good combustion practices, use of natural gas fuel for the project heater
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Volatile Organic Compounds (VOC)	8.5	MMBtu/H	0.0055	LB/MMBTU		
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Volatile Organic Compounds (VOC)	7.37	mm btu/hr	0			good combustion practices
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Volatile Organic Compounds (VOC)	0		0.0053	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Volatile Organic Compounds (VOC)	1.83	MMBTU/H	0.01	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
FL-0364	SEMINOLE GENERATING STATION	Two natural gas heaters (< 10 MMBtu/hr each)	03/21/2018	Volatile Organic Compounds (VOC)	9.9	MMBtu/hr	0.005	LB/MMBTU		

Table D-6.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, filterable (FPM)	3	MMBtu/hr (total)	0.006	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, filterable (FPM)	3.7	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, filterable (FPM)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, filterable (FPM)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, filterable (FPM)	4.8	MMBtu/hr, each	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, filterable (FPM)	3	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Particulate matter, filterable (FPM)	0		0			Good combustion practices and fire hydrogen rich plant fuel gas, 5% OPACITY
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, filterable (FPM)	5.12	MMBtu/hr	1.9	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, filterable (FPM)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE

Table D-6.5 Summary of Total PM10/PM2.5 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM10)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM2.5)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM10)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM2.5)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM10)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM2.5)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM10)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion)
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM2.5)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM10)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM2.5)	0		0.0079	GR/DSCF		Dust Collector and Scrubber

Table D-6.5 Summary of Total PM10/PM2.5 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM10)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM2.5)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM10)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM2.5)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Particulate matter, total (TPM2.5)	3	MMBTU/H	0			
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM10)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM2.5)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM10)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.

Table D-6.5 Summary of Total PM10/PM2.5 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM2.5)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM10)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM2.5)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM10)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM2.5)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM10)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM10)	7.37	mm btu/hr	0			good combustion practices
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM2.5)	7.37	mm btu/hr	0			good combustion practices
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM10)	1.83	MMBTU/H	0.01	LB/H		USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES

Table D-6.5 Summary of Total PM10/PM2.5 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM2.5)	1.83	MMBTU/H	0.003	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM10)	0		0			good engineering design and practices and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM2.5)	0		0			good engineering design and practices and use of clean fuels

Table D-6.6 Summary of H_2SO_4 BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Sulfuric Acid (mist, vapors, etc)	3.8	MMBTU/H	0.34	GR S/100 SCF	FUEL SUPPLIER RECORDS	Low sulfur fuel

Table D-6.7 Summary of CO_2e BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0371	WABASH VALLEY RESOURCES, LLC	Dewpoint Heater	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	1.44	MMBtu/hr	117	LB/MMBTU		Good Combustion Practices
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems â‰¤ 1 MMBtu	07/25/2022	Carbon Dioxide Equivalent (CO_2e)	3	MMBtu/hr (total)	1579	TONS/YR	12-MONTH ROLLING TOTAL	Design Requirements, Good Combustion & Operation Practices (GCOP) Plan
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	3.7	MMBTU/H	1934	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	3.8	MMBTU/H	6310	T/YR	12-MONTH ROLLING TIME PERIOD	Natural gas fuel
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	7	MMBTU/H	3590	T/YR	12-MO ROLLING TIME PERIOD; EACH UNIT	Energy efficiency
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		54701	TPY		Good Operating Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	4.8	MMBtu/hr, each	37581	TONS/YR	12-MONTH ROLLING, COMBINED	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	3	MMBtu/hr	30	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
*TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			Good combustion practices and fire hydrogenâ€ch plant fuel gas
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Carbon Dioxide Equivalent (CO_2e)	0		120	LB/MMBTU		Natural Gas Fuel

Table D-6.7 Summary of CO_2e BACT Determinations for Space Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OK-0164	MIDWEST CITY AIR DEPOT	Heaters/Boilers	01/08/2015	Carbon Dioxide Equivalent (CO_2e)	0	MMBTUH	153716	TONS PER YEAR	TOTAL FOR ALL UNITS.	1. Use pipeline-quality natural gas. 2. Good Combustion Practices. 3. Tune-ups for applicable boilers/heaters per 40CFR63, Subpart DDDDD.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		5858	TONS/YR		Use of fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	5.12	MMBtu/hr	2625	TONS/YR		good combustion practices and only pipeline quality natural gas shall be combusted
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	8.5	MMBtu/H	90	% AVG THERM EFF		Use only natural gas.
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Carbon Dioxide Equivalent (CO_2e)	7.37	mm btu/hr	0			good combustion/operating/maintenance practices and fueled by natural gas
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Carbon Dioxide Equivalent (CO_2e)	10	MMBtu/hr	117.1	LB/MMBTU		
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			good equipment design and good combustion practices

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Nitrogen Oxides (NO_x)	1529	HP	16.1	LB/H		State-of-the-art combustion design
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Nitrogen Oxides (NO_x)	1860	HP	19.68	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Nitrogen Oxides (NO_x)	2206	HP	24.71	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Nitrogen Oxides (NO_x)	2346	HP	21.6	LB/H		State-of-the-art combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Nitrogen Oxides (NO_x)	2682	HP	28.2	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Nitrogen Oxides (NO_x)	2947	HP	27.18	LB/H		State-of-the-art combustion design
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Nitrogen Oxides (NO_x)	3353	HP	37.41	LB/H	SEE NOTES.	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
*WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Nitrogen Oxides (NO_x)	2100	hp	24.6	LB/HR		Combustion Control (retarded timing and/or lean burn)
*WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Nitrogen Oxides (NO_x)	240	bhp	1.59	LB/HR		Combustion control (retarded timing and/or lean burn)
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Nitrogen Oxides (NO_x)	5000	HP	5.5	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Nitrogen Oxides (NO_x)	700	HP	4.97	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Nitrogen Oxides (NO_x)	1500	HP	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Nitrogen Oxides (NO_x)	22.68	MMBTU/H	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS IIII requirements.
*MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Nitrogen Oxides (NO_x)	22.68	MMBTU/H	6.4	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Nitrogen Oxides (NO_x)	6000	HP	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Nitrogen Oxides (NO_x)	2	MW	6.4	G/KW-H	HOURLY	State of the art combustion design.
*NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 1	11/21/2022	Nitrogen Oxides (NO_x)	510	hp	2.38	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Nitrogen Oxides (NO_x)	920	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	700	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
MI-0434	FLAT ROCK ASSEMBLY PLANT	EUENGINE01 through EUENGINE08	03/22/2018	Nitrogen Oxides (NO_x)	3633	BHP	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC+NOX	Good combustion practices.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Nitrogen Oxides (NO_x)	1100	KW	29.01	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Nitrogen Oxides (NO_x)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Nitrogen Oxides (NO_x)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Nitrogen Oxides (NO_x)	1529	HP	16.07	LB/H		State-of-the-art combustion design
*LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Nitrogen Oxides (NO_x)	0		5.53	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Nitrogen Oxides (NO_x)	27.9	Gal/hr	3.6	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Nitrogen Oxides (NO_x)	186.6	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year.
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Nitrogen Oxides (NO_x)	4474.2	KW	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Nitrogen Oxides (NO_x)	5051	HP	6.4	G/KW-H	6.4 GRAMS NOX + NMHC/KW-HR	Certified to meet Tier 2 standards and good combustion practices
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Nitrogen Oxides (NO_x)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Nitrogen Oxides (NO_x)	0		5.36	G/KWH		Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Nitrogen Oxides (NO_x)	1389	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Nitrogen Oxides (NO_x)	1800	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Nitrogen Oxides (NO_x)	2922	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Nitrogen Oxides (NO_x)	2015.7	HP	0			
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Nitrogen Oxides (NO_x)	420	brake hp	4	G/KW-HR		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Nitrogen Oxides (NO_x)	2012	hp	4.8	G/HP-HR		
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Limited operating hours.
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	3.53	LB/H	HOURLY	Certified Engines, Limited Operating Hours
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Nitrogen Oxides (NO_x)	500	H/YR	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, limited operating hours.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, limited operating hours.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	21.2	LB/H	HOURLY	Certified engines, limited operating hours
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, limited operating hours
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Nitrogen Oxides (NO_x)	500	H/YR	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, limited operating hours.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	4.4	LB/H	HOURLY	Certified Engines, Limited Operating Hours
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Nitrogen Oxides (NO_x)	650	horsepower	6.6	LB/HR		Compliance with NSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Nitrogen Oxides (NO_x)	1474	horsepower	19.23	LB/HR		Compliance with NSPS Subpart IIII
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	Main Propulsion Generator Engines	12/31/2014	Nitrogen Oxides (NO_x)	0		0			Use of good combustion practices based on the most recent manufacturerâ€™s specifications issued for these engines at the time that the engines are operating under this permit
*AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Nitrogen Oxides (NO_x)	0		3.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Nitrogen Oxides (NO_x)	0		5.36	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	06/07/2021	Nitrogen Oxides (NO_x)	14.82	MMBtu/hour	6.4	G/KW-HOUR	FOR NMHC+NOX	
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	07/27/2018	Nitrogen Oxides (NO_x)	14.82	MMBtu/hour	6.4	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Nitrogen Oxides (NO_x)	0		4.86	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
MI-0418	WARREN TECHNICAL CENTER	Four (4) emergency engines in FG-BACKUPGENS	01/14/2015	Nitrogen Oxides (NO_x)	2710	KW	7.13	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0418	WARREN TECHNICAL CENTER	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	01/14/2015	Nitrogen Oxides (NO_x)	3490	KW	8	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Nitrogen Oxides (NO_x)	2695	hp	4.8	GRAMS/ HP-H		
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Nitrogen Oxides (NO_x)	5364	HP	5.6	G/KW-H		Good Combustion and Operating Practices
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Nitrogen Oxides (NO_x)	1341	HP	14.96	LB/H	SEE NOTES.	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	143.5	MMBtu/hr	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	Selective Catalytic Reduction (SCR) and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	1500	kWe	8	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Nitrogen Oxides (NO_x)	1100	KW	5.3	G/HP-H	HOURLY; EACH ENGINE	
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Nitrogen Oxides (NO_x)	1250	kW	6.4	GRAMS	KILOWATT-HOUR	
OH-0379	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	02/06/2019	Nitrogen Oxides (NO_x)	3131	HP	3.45	LB/H		Tier IV engine□ Tier IV NSPS standards certified by engine manufacturer.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Nitrogen Oxides (NO_x)	2206	HP	23.21	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Nitrogen Oxides (NO_x)	3131	HP	0			Tier IV NSPS standards certified by engine manufacturer.
TX-0671	PROJECT JUMBO	Engines	12/01/2014	Nitrogen Oxides (NO_x)	0		5.43	G/KW-H		Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Nitrogen Oxides (NO_x)	610	hp	3	GRAMS/ HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Nitrogen Oxides (NO_x)	891	hp	4.8	GRAMS/ HP-H		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Nitrogen Oxides (NO_x)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Nitrogen Oxides (NO_x)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0879	MOTIVA PORT ARTHUR TERMINAL	Emergency Firewater Engine	02/19/2020	Nitrogen Oxides (NO_x)	0		0			Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.
WV-0027	INWOOD	Emergency Generator - ESDG14	09/15/2017	Nitrogen Oxides (NO_x)	900	bhp	4.77	G/HP-HR		Engine Design
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Nitrogen Oxides (NO_x)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
AL-0328	PLANT BARRY	Diesel Emergency Engines	11/09/2020	Nitrogen Oxides (NO_x)	0		3	GR/BHP-HR	NMHC + NOX	
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Nitrogen Oxides (NO_x)	0		0.4	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Nitrogen Oxides (NO_x)	3634	Horsepower	5.6	G/KW-HR		
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Nitrogen Oxides (NO_x)	3985	hp	6.4	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Nitrogen Oxides (NO_x)	3600	HP EACH	4.42	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Nitrogen Oxides (NO_x)	2800	HP	6.4	G/KWH	TIER II NOX + NMHC LIMIT	Tier II diesel engine

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Nitrogen Oxides (NO_x)	750	HP	4	G/KWH	COMBINED NOX + NMHC LIMIT	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Nitrogen Oxides (NO_x)	3600	HP	4.42	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Nitrogen Oxides (NO_x)	500	HP	2.83	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Nitrogen Oxides (NO_x)	3000	Horsepower	4.8	G/HP-HR		certified engine
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (400 kW)	01/11/2024	Nitrogen Oxides (NO_x)	619	HP	2.29	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (1000 kW)	01/11/2024	Nitrogen Oxides (NO_x)	1000	kW	3.81	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (2000 kW)	01/11/2024	Nitrogen Oxides (NO_x)	2000	kW	3.81	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
*IN-0371	WABASH VALLEY RESOURCES, LLC	Ammonia Plant Emergency Generator	01/11/2024	Nitrogen Oxides (NO_x)	500	kW	4.8	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Nitrogen Oxides (NO_x)	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Nitrogen Oxides (NO_x)	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Nitrogen Oxides (NO_x)	700	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Nitrogen Oxides (NO_x)	1341	HP	14.16	LB/HR	HOURLY MAXIMUM	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Nitrogen Oxides (NO_x)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Nitrogen Oxides (NO_x)	2922	hp (each)	6.4	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Nitrogen Oxides (NO_x)	2584	HP	27.34	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Nitrogen Oxides (NO_x)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Nitrogen Oxides (NO_x)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Nitrogen Oxides (NO_x)	0		0			Complying with 40 CFR 60 Subpart IIII
*LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Nitrogen Oxides (NO_x)	4290	kw	8.46	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Nitrogen Oxides (NO_x)	634	kW	3.1	G/HP-H		Good Combustion and Operating Practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Nitrogen Oxides (NO_x)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Nitrogen Oxides (NO_x)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Nitrogen Oxides (NO_x)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Nitrogen Oxides (NO_x)	2937	hp	4.8	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Nitrogen Oxides (NO_x)	670.5	horsepower	4.24	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Nitrogen Oxides (NO_x)	670.5	horsepower	4.24	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Nitrogen Oxides (NO_x)	3634	horsepower	38.24	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Nitrogen Oxides (NO_x)	2923	horsepower	28.48	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Nitrogen Oxides (NO_x)	2923	horsepower	28.48	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII

Table D-7.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*SD-0005	DEER CREEK STATION	Emergency Generator	06/29/2010	Nitrogen Oxides (NO_x)	2000	Kilowatts	0			
*SD-0005	DEER CREEK STATION	Fire Water Pump	06/29/2010	Nitrogen Oxides (NO_x)	577	horsepower	0			
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Nitrogen Oxides (NO_x)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Nitrogen Oxides (NO_x)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Nitrogen Oxides (NO_x)	0		0			limited to 100 hours per year of non-emergency operation
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Nitrogen Oxides (NO_x)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Nitrogen Oxides (NO_x)	500	H/YR	4.8	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Nitrogen Oxides (NO_x)	500	H/YR	4.8	G/HP-H		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Nitrogen Oxides (NO_x)	1490	HP	4.8	G/HP-H		Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations.

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Generator Engines	09/02/2016	Carbon Monoxide	0		2.61	G/BHP-HR		
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Carbon Monoxide	1529	HP	8.8	LB/H		State-of-the-art combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Carbon Monoxide	2206	HP	12.64	LB/H		Good combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Carbon Monoxide	2346	HP	13.5	LB/H		State-of-the-art combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Carbon Monoxide	2682	HP	15.4	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Carbon Monoxide	2947	HP	16.96	LB/H		State-of-the-art combustion design
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Carbon Monoxide	3353	HP	19.25	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
*WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Carbon Monoxide	2100	hp	1.94	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine
*WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Carbon Monoxide	240	bhp	1.38	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Carbon Monoxide	5000	HP	28.8	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Carbon Monoxide	700	HP	4.01	LB/H		Good combustion design
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Carbon Monoxide	1500	HP	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Carbon Monoxide	22.68	MMBTU/H	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
*MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Carbon Monoxide	22.68	MMBTU/H	3.5	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Carbon Monoxide	6000	HP	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Carbon Monoxide	2	MW	3.5	G/KW-H	HOURLY	State of the art combustion design.
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Three 3300-kW ULSD emergency generators	03/09/2016	Carbon Monoxide	0		3.5	G / KW-HR		Use of clean engine
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Carbon Monoxide	920	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Carbon Monoxide	700	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Carbon Monoxide	1100	KW	8.49	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Carbon Monoxide	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Carbon Monoxide	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Carbon Monoxide	1529	HP	8.8	LB/H		State-of-the-art combustion design
*LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Carbon Monoxide	0		0.55	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Carbon Monoxide	27.9	Gal/hr	3.3	G/HP-HR		Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Carbon Monoxide	186.6	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Oxidation Catalyst, Good Combustion Practices, and 500 hour limit per year.
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Carbon Monoxide	4474.2	KW	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Carbon Monoxide	4474.2	KW	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Carbon Monoxide	5051	HP	3.5	G/KW-H		Certified to meet Tier 2 standards and good combustion practices
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Carbon Monoxide	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Carbon Monoxide	0		0.6	G/KWH		Good Combustion Practices
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Carbon Monoxide	1389	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Carbon Monoxide	1800	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Carbon Monoxide	2922	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Carbon Monoxide	2015.7	HP	0			

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Carbon Monoxide	420	brake hp	3.5	G/KW-HR		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Carbon Monoxide	2012	hp	2.6	G/HP-HR		
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good Design and Combustion Practices
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good design and combustion practices
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and combustion practices.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good Design and Combustion Practices
IL-0130	JACKSON ENERGY CENTER	Emergency Engine	12/31/2018	Carbon Monoxide	1500	kW	3.5	G/KW-HR		
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Carbon Monoxide	650	horsepower	0.9	LB/HR		Compliance with NSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Carbon Monoxide	1474	horsepower	0.51	LB/HR		Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Carbon Monoxide	0		0.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Carbon Monoxide	0		0.26	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Carbon Monoxide	0		1	G/HP-HR		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Carbon Monoxide	0		0.6	G/KWH		Good Combustion Practices

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	06/07/2021	Carbon Monoxide	14.82	MMBtu/hour	3.5	G/KW-HOUR		
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	07/27/2018	Carbon Monoxide	14.82	MMBtu/hour	3.5	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Carbon Monoxide	0		3.5	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Carbon Monoxide	53.6	gal/hr	2.6	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisionâ€™s inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Carbon Monoxide	2695	hp	2.6	GRAMS/HP-H		
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Carbon Monoxide	5364	HP	3.5	G/KW-H		Good Combustion and Operating Practices.

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Carbon Monoxide	1341	HP	7.7	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Carbon Monoxide	0		0.6	GM/HP-HR		
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Carbon Monoxide	143.5	MMBtu/hr	0.18	G/KW-HR (ULSD)	3-HOUR AVERAGE	Oxidation Catalyst and Maintain Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Carbon Monoxide	1500	kWe	4.38	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Carbon Monoxide	1100	KW	0.15	G/HP-H	HOURLY; EACH ENGINE	
IL-0129	CPV THREE RIVERS ENERGY CENTER	Emergency Engines	07/30/2018	Carbon Monoxide	0		0			
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Carbon Monoxide	1250	kW	3.5	GRAMS	KILOWATT-HOUR	
OH-0383	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	07/17/2020	Carbon Monoxide	3131	HP	0			Tier IV engine Good combustion practices
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Carbon Monoxide	2206	HP	12.69	LB/H		Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Carbon Monoxide	3131	HP	0			Tier IV NSPS standards certified by engine manufacturer.
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Carbon Monoxide	610	hp	2.6	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Carbon Monoxide	891	hp	2.6	GRAMS/HP-H		
FL-0363	DANIA BEACH ENERGY CENTER	Two 3300 kW emergency generators	12/04/2017	Carbon Monoxide	0		3.5	GRAMS PER KWH		Certified engine
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Carbon Monoxide	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Carbon Monoxide	0		0			Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Carbon Monoxide	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
AL-0328	PLANT BARRY	Diesel Emergency Engines	11/09/2020	Carbon Monoxide	0		2.6	G/BHP-HR		
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Carbon Monoxide	0		3.5	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Carbon Monoxide	3634	Horsepower	3.5	G/KW-HR		
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Carbon Monoxide	3985	hp	3.5	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Carbon Monoxide	3600	HP EACH	2.61	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Carbon Monoxide	2800	HP	3.5	G/KWH		Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Carbon Monoxide	750	HP	3.5	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Carbon Monoxide	3600	HP	2.61	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Carbon Monoxide	500	HP	2.6	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Carbon Monoxide	3000	Horsepower	2.61	G/HP-HR		oxidation catalyst and certified engine
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Carbon Monoxide	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Carbon Monoxide	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Carbon Monoxide	700	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Carbon Monoxide	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Carbon Monoxide	2922	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Carbon Monoxide	2584	HP	14.81	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Carbon Monoxide	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Carbon Monoxide	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Carbon Monoxide	0		0			Complying with 40 CFR 60 Subpart IIII
*LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Carbon Monoxide	4290	kw	1.21	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Carbon Monoxide	634	kW	3.7	G/HP-H		Good Combustion and Operating Practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Carbon Monoxide	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Carbon Monoxide	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Carbon Monoxide	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Carbon Monoxide	575	hp	3.97	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Carbon Monoxide	2937	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Carbon Monoxide	670.5	horsepower	3.81	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Carbon Monoxide	670.5	horsepower	3.81	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Carbon Monoxide	3634	horsepower	20.91	LB/HR		Compliance with 40 CFR 60 Subpart IIII

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Carbon Monoxide	2923	horsepower	2.9	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Carbon Monoxide	2923	horsepower	2.9	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Carbon Monoxide	44	H/YR	3.5	LB/H		use of ultra low sulfur diesel oil a clean burning fuel
NY-0103	CRICKET VALLEY ENERGY CENTER	Black start generator	02/03/2016	Carbon Monoxide	3000	KW	2.6	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
*SD-0005	DEER CREEK STATION	Emergency Generator	06/29/2010	Carbon Monoxide	2000	Kilowatts	0			
*SD-0005	DEER CREEK STATION	Fire Water Pump	06/29/2010	Carbon Monoxide	577	horsepower	0			
TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Carbon Monoxide	0		0.0055	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Carbon Monoxide	0		0.6	G/KW HR		Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Carbon Monoxide	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Carbon Monoxide	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Carbon Monoxide	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Carbon Monoxide	0		2.61	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Carbon Monoxide	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Carbon Monoxide	18.7	MMBTU/HR	0.006	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Carbon Monoxide	500	H/YR	2.6	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Carbon Monoxide	500	H/YR	2.6	G/HP-H		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-7.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Carbon Monoxide	1490	HP	2.6	G/HP-H		Operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations.

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Volatile Organic Compounds (VOC)	1529	HP	2	LB/H		State-of-the-art combustion design
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Volatile Organic Compounds (VOC)	1860	HP	19.68	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Volatile Organic Compounds (VOC)	2206	HP	24.71	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Volatile Organic Compounds (VOC)	2346	HP	3.1	LB/H		
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Volatile Organic Compounds (VOC)	2947	HP	3.84	LB/H		State-of-the-art combustion design
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Volatile Organic Compounds (VOC)	3353	HP	37.41	LB/H	SEE NOTES.	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
*WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Volatile Organic Compounds (VOC)	2100	hp	0.46	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine
*WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Volatile Organic Compounds (VOC)	240	bhp	1.59	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Volatile Organic Compounds (VOC)	5000	HP	1.6	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Diesel-Fired Emergency Fire Pump (P36)	12/10/2019	Volatile Organic Compounds (VOC)	510	HP	200	H/Y	IN ANY CONSECUTIVE 12-MONTH PERIOD	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Volatile Organic Compounds (VOC)	700	HP	4.97	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
VA-0327	PERDUE GRAIN AND OILSEED, LLC	Emergency Generator	07/12/2017	Volatile Organic Compounds (VOC)	0		0.49	LB/HR		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices.

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Volatile Organic Compounds (VOC)	22.68	MMBTU/H	1.87	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Volatile Organic Compounds (VOC)	2	MW	1.89	LB/H	HOURLY	State of the art combustion design.
*NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 1	11/21/2022	Volatile Organic Compounds (VOC)	510	hp	0.62	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Volatile Organic Compounds (VOC)	920	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	700	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Volatile Organic Compounds (VOC)	1529	HP	2	LB/H		State-of-the-art combustion design
*LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Volatile Organic Compounds (VOC)	0		0.4	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Volatile Organic Compounds (VOC)	27.9	Gal/hr	0.19	G/HP-HR		Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Volatile Organic Compounds (VOC)	186.6	gph	0.18	G/HP-HR	3-HOUR AVERAGE	Oxidation Catalyst, Good combustion practices, and limit operation to 500 hours per year.
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Volatile Organic Compounds (VOC)	5051	HP	0.4	G/KW-H		Certified to meet Tier 2 standards and good combustion practices
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Volatile Organic Compounds (VOC)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Must meet the standards of 40 CFR 60, Subpart IIII
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Volatile Organic Compounds (VOC)	0		0.56	G/KWH		Good Combustion Practices
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Volatile Organic Compounds (VOC)	2015.7	HP	1.24	LB/H		
OK-0175	WILDHORSE TERMINAL	Emergency Use Engines > 500 HP	06/29/2017	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices. Certified to meet EPA Tier 3 engine standards. Shall be limited to operate at no more than 500 hr/yr.
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Volatile Organic Compounds (VOC)	650	horsepower	0.13	LB/HR		Compliance with NNSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Volatile Organic Compounds (VOC)	1474	horsepower	0.04	LB/HR		Compliance with NSPS Subpart IIII
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Volatile Organic Compounds (VOC)	0		0.56	G/KWH		Good Combustion Practices
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Volatile Organic Compounds (VOC)	0		1.55	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Volatile Organic Compounds (VOC)	53.6	gal/hr	4.77	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Volatile Organic Compounds (VOC)	2695	hp	0.0007	LB/HP-H		
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Volatile Organic Compounds (VOC)	5364	HP	0.79	G/KW-H		Good combustion and operating practices.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Volatile Organic Compounds (VOC)	1341	HP	14.96	LB/H	SEE NOTES.	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Volatile Organic Compounds (VOC)	143.5	MMBtu/hr	0.21	G/KW-HR (ULSD)	3-HOUR AVERAGE	Oxidation Catalyst and Good Combustion Practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Volatile Organic Compounds (VOC)	1100	KW	0.86	LB/H	HOURLY; EACH ENGINE	
OK-0181	WILDHORSE TERMINAL	EMERGENCY USE ENGINES > 500 HP	09/11/2019	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices. Certified to meet EPA Tier 3 engine standards. Each engine shall be limited to operate not more than 500 hours per year.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Volatile Organic Compounds (VOC)	2206	HP	23.21	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Volatile Organic Compounds (VOC)	610	hp	0.0007	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Volatile Organic Compounds (VOC)	891	hp	0.0007	LB/HP-H		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Volatile Organic Compounds (VOC)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Volatile Organic Compounds (VOC)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0879	MOTIVA PORT ARTHUR TERMINAL	Emergency Firewater Engine	02/19/2020	Volatile Organic Compounds (VOC)	0		0.1	G/HP HR		Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Volatile Organic Compounds (VOC)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Volatile Organic Compounds (VOC)	0		1.9	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Volatile Organic Compounds (VOC)	3634	Horsepower	0.8	G/KW-HR		
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Volatile Organic Compounds (VOC)	3985	hp	6.4	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Volatile Organic Compounds (VOC)	3600	HP EACH	0.35	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Volatile Organic Compounds (VOC)	2800	HP	6.4	G/KWH	TIER II NOX + NMHC LIMIT	Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Volatile Organic Compounds (VOC)	750	HP	4	G/KWH	COMBINED NOX + NMHC LIMIT	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Volatile Organic Compounds (VOC)	3600	HP	0.35	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Volatile Organic Compounds (VOC)	500	HP	0.141	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Volatile Organic Compounds (VOC)	3000	Horsepower	0.32	G/HP-HR		certified engine
LA-0276	BATON ROUGE JUNCTION FACILITY	Fire Pump Engines (2 units)	12/15/2016	Volatile Organic Compounds (VOC)	700	hp	0			Comply with standards of NSPS Subpart IIII
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Volatile Organic Compounds (VOC)	1341	HP	0.83	LB/HR	HOURLY MAXIMUM	Good combustion practices consistent with the manufacturer's recommendations to maximize fuel efficiency and minimize emissions
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Volatile Organic Compounds (VOC)	2922	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Volatile Organic Compounds (VOC)	2584	HP	27.34	LB/H	HOURLY MAXIMUM	Good combustion practices
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Volatile Organic Compounds (VOC)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
*LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Volatile Organic Compounds (VOC)	4290	kw	0.322	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Volatile Organic Compounds (VOC)	634	kW	0.44	G/HP-H		Good combustion and operating practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Volatile Organic Compounds (VOC)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Volatile Organic Compounds (VOC)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Volatile Organic Compounds (VOC)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Volatile Organic Compounds (VOC)	575	hp	0.32	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0390	DERIDDER SAWMILL	GEN-1 - Emergency Generator No. 1	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC.
LA-0390	DERIDDER SAWMILL	GEN-2 - Emergency Generator No. 2	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC
LA-0390	DERIDDER SAWMILL	GEN-3 - Emergency Generator No. 2	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good Combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitations for VOC
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Volatile Organic Compounds (VOC)	2937	hp	4.8	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII standards, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Volatile Organic Compounds (VOC)	670.5	horsepower	0.11	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Volatile Organic Compounds (VOC)	670.5	horsepower	0.11	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Volatile Organic Compounds (VOC)	3634	horsepower	2.29	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Volatile Organic Compounds (VOC)	2923	horsepower	2.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Volatile Organic Compounds (VOC)	2923	horsepower	2.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Volatile Organic Compounds (VOC)	0		0.0007	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.

Table D-7.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Volatile Organic Compounds (VOC)	0		0.12	G/KW HR		Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Volatile Organic Compounds (VOC)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Volatile Organic Compounds (VOC)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Volatile Organic Compounds (VOC)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Volatile Organic Compounds (VOC)	0		0.5	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Volatile Organic Compounds (VOC)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Volatile Organic Compounds (VOC)	18.7	MMBTU/HR	0.001	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Volatile Organic Compounds (VOC)	1490	HP	0.32	G/HP-H		Operation limited to 500 hours/year and operate and maintain generator according to the manufacturerâ€™s recommendations

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	17.11	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	17.11	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS IIII requirements.
MI-0451	MEC NORTH, LLC	17.11	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	17.11	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0423	INDECK NILES, LLC	17.11	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, filterable (FPM)	22.68	MMBTU/H	0.2	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
*MI-0445	INDECK NILES, LLC	17.11	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, filterable (FPM)	22.68	MMBTU/H	0.2	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	17.11	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, filterable (FPM)	2	MW	0.2	G/KW-H	HOURLY	State of the art combustion design
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, filterable (FPM)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*LA-0324	COMMONWEALTH LNG FACILITY	17.11	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Particulate matter, filterable (FPM10)	0		0.125	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
*LA-0324	COMMONWEALTH LNG FACILITY	17.11	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Particulate matter, filterable (FPM2.5)	0		0.125	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	17.11	Emergency Generator	11/21/2014	Particulate matter, filterable (FPM2.5)	2015.7	HP	0			
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	17.11	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0421	GRAYLING PARTICLEBOARD	17.11	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, filterable (FPM)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	17.11	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	17.11	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, filterable (FPM)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	17.11	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	17.11	1,500 kW Emergency Diesel Generator	07/27/2018	Particulate matter, filterable (FPM)	14.82	MMBtu/hour	0.2	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0163	BIG RIVER STEEL LLC	17.11	Emergency Engines	06/09/2019	Particulate matter, filterable (FPM)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
KY-0109	FRITZ WINTER NORTH AMERICA, LP	17.11	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, filterable (FPM)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Emergency Camp Generators	01/23/2015	Particulate matter, filterable (FPM10)	2695	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Emergency Camp Generators	01/23/2015	Particulate matter, filterable (FPM2.5)	2695	hp	0.15	GRAMS/HP-H		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	17.11	2000 kW Emergency Generator	12/23/2015	Particulate matter, filterable (FPM)	0		0.025	GM/HP-HR		
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)		Clean Fuel and Good Combustion Practices

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM10)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM2.5)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM)	0		0.2	GR/KWH		Emergency Diesel Engine and Fire Pump Subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM10)	0		0.2	G/KWH		One diesel engine and fire pump subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM2.5)	0		0.2	GR/KWH		One diesel fuel emergency engine and one fire pump subject to NSPS Subpart IIII - Combustion Control and Limited
OH-0379	PETMIN USA INCORPORATED	17.11	Emergency Generators (P005 and P006)	02/06/2019	Particulate matter, filterable (FPM10)	3131	HP	0.15	LB/H		Tier IV engine Good combustion practices
OH-0379	PETMIN USA INCORPORATED	17.11	Emergency Generators (P005 and P006)	02/06/2019	Particulate matter, filterable (FPM2.5)	3131	HP	0.15	LB/H		Tier IV engine Good combustion practices
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Fine Water Pumps	01/23/2015	Particulate matter, filterable (FPM10)	610	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Fine Water Pumps	01/23/2015	Particulate matter, filterable (FPM2.5)	610	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Bulk Tank Generator Engines	01/23/2015	Particulate matter, filterable (FPM10)	891	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Bulk Tank Generator Engines	01/23/2015	Particulate matter, filterable (FPM2.5)	891	hp	0.15	GRAMS/HP-H		
FL-0363	DANIA BEACH ENERGY CENTER	17.11	Two 3300 kW emergency generators	12/04/2017	Particulate matter, filterable (FPM)	0		0.2	GRAMS PER KWH		Clean fuel
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency generator	02/06/2020	Particulate matter, filterable (FPM10)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency generator	02/06/2020	Particulate matter, filterable (FPM2.5)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM10)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM2.5)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
AL-0328	PLANT BARRY	17.11	Diesel Emergency Engines	11/09/2020	Particulate matter, filterable (FPM)	0		0.15	G/BHP-HR		
AR-0161	SUN BIO MATERIAL COMPANY	17.11	Emergency Engines	09/23/2019	Particulate matter, filterable (FPM)	0		0.02	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	17.11	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, filterable (FPM)	3634	Horsepower	0.2	G/KW-HR		
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, filterable (FPM)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, filterable (FPM)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, filterable (FPM)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0313	ST. CHARLES POWER STATION	17.11	SCPS Emergency Diesel Generator 1	08/31/2016	Particulate matter, filterable (FPM10)	2584	HP	0.86	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
LA-0313	ST. CHARLES POWER STATION	17.11	SCPS Emergency Diesel Generator 1	08/31/2016	Particulate matter, filterable (FPM2.5)	2584	HP	0.86	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
*LA-0324	COMMONWEALTH LNG FACILITY	17.11	Generator Engines (EQT0016)	03/28/2023	Particulate matter, filterable (FPM2.5)	4290	kw	0.067	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
*LA-0324	COMMONWEALTH LNG FACILITY	17.11	Generator Engines (EQT0016)	03/28/2023	Particulate matter, filterable (FPM10)	4290	kw	0.067	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	17.11	Emergency Generator Diesel Engines	01/06/2020	Particulate matter, filterable (FPM2.5)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	17.11	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, filterable (FPM)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NY-0103	CRICKET VALLEY ENERGY CENTER	17.11	Black start generator	02/03/2016	Particulate matter, filterable (FPM)	3000	KW	0.15	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance
*SD-0005	DEER CREEK STATION	17.11	Emergency Generator	06/29/2010	Particulate matter, filterable (FPM)	2000	Kilowatts	0			
*SD-0005	DEER CREEK STATION	17.11	Fire Water Pump	06/29/2010	Particulate matter, filterable (FPM)	577	horsepower	0			
TX-0888	ORANGE POLYETHYLENE PLANT	17.11	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, filterable (FPM)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0888	ORANGE POLYETHYLENE PLANT	17.11	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, filterable (FPM10)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM10)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM2.5)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM)	0		0			limited to 100 hours per year of non-emergency operation
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM10)	0		0			limited to 100 hours per year of non-emergency operation
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM2.5)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	17.11	DIESEL GENERATOR	03/17/2021	Particulate matter, filterable (FPM)	0		0.022	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0915	UNIT 5	17.11	DIESEL GENERATOR	03/17/2021	Particulate matter, filterable (FPM10)	0		0.022	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards

Table D-7.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM10)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM2.5)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM)	18.7	MMBTU/HR	0.0003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM10)	18.7	MMBTU/HR	0.0003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM2.5)	18.7	MMBTU/HR	0.003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	17.11	Emergency Diesel GEN	04/26/2018	Particulate matter, filterable (FPM)	500	H/YR	0.15	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	17.11	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, filterable (FPM)	500	H/YR	0.15	G/HP-H		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Particulate matter, total (TPM10)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Particulate matter, total (TPM2.5)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Particulate matter, total (TPM10)	1860	HP	0.62	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Particulate matter, total (TPM2.5)	1860	HP	0.62	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Particulate matter, total (TPM10)	2206	HP	0.73	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Particulate matter, total (TPM2.5)	2206	HP	0.73	LB/H		Good combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Particulate matter, total (TPM10)	2346	HP	0.77	LB/H		State-of-the-art combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Particulate matter, total (TPM2.5)	2346	HP	0.77	LB/H		State-of-the-art combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Particulate matter, total (TPM10)	2682	HP	1.01	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Particulate matter, total (TPM2.5)	2682	HP	1.01	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Particulate matter, total (TPM10)	2947	HP	0.97	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Particulate matter, total (TPM2.5)	2947	HP	0.97	LB/H		State-of-the-art combustion design
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Particulate matter, total (TPM10)	3353	HP	1.1	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Particulate matter, total (TPM2.5)	3353	HP	1.1	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Particulate matter, total (TPM10)	5000	HP	0.2	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Particulate matter, total (TPM2.5)	5000	HP	0.2	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Particulate matter, total (TPM10)	700	HP	0.23	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Particulate matter, total (TPM2.5)	700	HP	0.23	LB/H		Good combustion design
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM10)	1500	HP	0.69	LB/H	HOURLY	Good combustion practices, burn ultra-low sulfur diesel fuel and be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	1500	HP	0.69	LB/H	HOURLY	Ultra low-sulfur diesel fuel.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, total (TPM10)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, total (TPM2.5)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices.
*MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, total (TPM10)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices
*MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, total (TPM2.5)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Particulate matter, total (TPM10)	6000	HP	2.7	LB/H	HOURLY	Good combustion practices, burn ultra low sulfur diesel fuel, and be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	6000	HP	2.7	LB/H	HOURLY	Ultra low sulfur diesel fuel.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, total (TPM10)	2	MW	1.18	LB/H	HOURLY	State of the art combustion design
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, total (TPM2.5)	2	MW	1.18	LB/H	HOURLY	State of the art combustion design.
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Particulate matter, total (TPM10)	19.04	MMBTU/HR	0.4	LB/HR		
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Particulate matter, total (TPM2.5)	19.04	MMBTU/HR	0.4	LB/HR		
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, total (TPM10)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, total (TPM2.5)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Particulate matter, total (TPM10)	1100	KW	0.77	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Particulate matter, total (TPM2.5)	1100	KW	0.77	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Particulate matter, total (TPM10)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Particulate matter, total (TPM2.5)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Particulate matter, total (TPM10)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Particulate matter, total (TPM2.5)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Particulate matter, total (TPM10)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Particulate matter, total (TPM2.5)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Particulate matter, total (TPM10)	27.9	Gal/hr	0.19	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Particulate matter, total (TPM2.5)	27.9	Gal/hr	0.19	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Particulate matter, total (TPM10)	186.6	gph	0.045	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Particulate matter, total (TPM2.5)	186.6	gph	0.045	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Particulate matter, total (TPM10)	4474.2	KW	1	LB/H	HOURLY	Good combustion practices, burn ultra-low diesel fuel and be NSPS compliant.
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Particulate matter, total (TPM2.5)	4474.2	KW	1	LB/H	HOURLY	ultra-low sulfur diesel fuel
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Particulate matter, total (TPM10)	4474.2	KW	1	LB/H	HOURLY	Good combustion practices, burn ultra-low diesel fuel, and be NSPS compliant.
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Particulate matter, total (TPM2.5)	4474.2	KW	1	LB/H	HOURLY	Ultra-low sulfur diesel fuel
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Particulate matter, total (TPM10)	5051	HP	0.07	LB/H	EACH GENERATOR	Certified to meet Tier 2 standards and good combustion practices

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Particulate matter, total (TPM2.5)	5051	HP	0.07	LB/H	EACH GENERATOR	Certified to meet Tier 2 standards and good combustion practices
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Particulate matter, total (TPM2.5)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Meet the standards of 40 CFR 60, Subpart IIII
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Particulate matter, total (TPM10)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Must meet the standards of 40 CFR 60, Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Particulate matter, total (TPM10)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Particulate matter, total (TPM2.5)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Particulate matter, total (TPM10)	0		0.17	G/KWH		Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Particulate matter, total (TPM2.5)	0		0.17	G/KWH		Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Particulate matter, total (TPM10)	1389	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Particulate matter, total (TPM10)	1800	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Particulate matter, total (TPM10)	420	brake hp	0.2	G/KW-HR)		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Particulate matter, total (TPM2.5)	420	brake hp	0.2	G/KW-HR		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Particulate matter, total (TPM10)	2012	hp	0.15	G PER HP-HR		

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Particulate matter, total (TPM2.5)	2012	hp	0.15	G/HP-HR		
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, total (TPM10)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, total (TPM2.5)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, total (TPM10)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, total (TPM2.5)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Particulate matter, total (TPM10)	650	horsepower	0.15	LB/HR		Compliance with NSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Particulate matter, total (TPM2.5)	650	horsepower	0.15	LB/HR		Compliance with NSPS IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Particulate matter, total (TPM10)	1474	horsepower	0.08	LB/HR		Compliance with NSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Particulate matter, total (TPM2.5)	1474	horsepower	0.08	LB/HR		Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Particulate matter, total (TPM10)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Particulate matter, total (TPM2.5)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Particulate matter, total (TPM10)	0		0.04	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Particulate matter, total (TPM2.5)	0		0.04	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Particulate matter, total (TPM10)	0		0.2	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Particulate matter, total (TPM2.5)	0		2	HP-HR		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Particulate matter, total (TPM10)	0		0.17	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Particulate matter, total (TPM2.5)	0		0.17	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Particulate matter, total (TPM10)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Particulate matter, total (TPM2.5)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, total (TPM2.5)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, &; #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, total (TPM10)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (50kW)	09/21/2018	Particulate matter, total (TPM10)	5364	HP	0.2	G/KW-H		Good combustion and operating practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (50kW)	09/21/2018	Particulate matter, total (TPM2.5)	5364	HP	0.2	G/KW-H		Good combustion and operating practices.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Particulate matter, total (TPM10)	1341	HP	0.44	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Particulate matter, total (TPM2.5)	1341	HP	0.44	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Particulate matter, total (TPM10)	0		0.025	GM/HP-HR		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Particulate matter, total (TPM2.5)	0		0.025	GM/HP-HR		
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM10)	143.5	MMBtu/hr	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	143.5	MMBtu/hr	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Particulate matter, total (TPM10)	1500	kWe	0.25	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	1500	kWe	0.25	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Particulate matter, total (TPM10)	1100	KW	7.85	LB/1000 GAL	HOURLY; EACH ENGINE	Good combustion practices and ultra low sulfur diesel
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Particulate matter, total (TPM2.5)	1100	KW	7.55	LB/1000 GAL	HOURLY; EACH ENGINE	Good combustion practices and ultra low sulfur diesel.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Particulate matter, total (TPM10)	2206	HP	0.73	LB/H		Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Particulate matter, total (TPM2.5)	2206	HP	0.73	LB/H		Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Particulate matter, total (TPM10)	3131	HP	0.15	G/B-HP-H		Tier IV engine and Good combustion practices

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Particulate matter, total (TPM2.5)	3131	HP	0.15	G/B-HP-H		Tier IV engine and Good combustion practices
WV-0027	INWOOD	Emergency Generator - ESDG14	09/15/2017	Particulate matter, total (TPM10)	900	bhp	0.2	G/HP-HR		ULSD
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Particulate matter, total (TPM2.5)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Particulate matter, total (TPM10)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Particulate matter, total (TPM10)	0		0.02	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Particulate matter, total (TPM2.5)	0		0.02	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, total (TPM10)	3634	Horsepower	0.2	G/KW-HR		
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, total (TPM2.5)	3634	Horsepower	0.2	G/KW-HR		
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Particulate matter, total (TPM10)	3985	hp	0.2	G/KW-HR	3-HR AVG	
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Particulate matter, total (TPM2.5)	3985	hp	0.2	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Particulate matter, total (TPM10)	3600	HP EACH	0.15	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Particulate matter, total (TPM2.5)	3600	HP EACH	0.15	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Particulate matter, total (TPM10)	2800	HP	0.2	G/KWH		Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Particulate matter, total (TPM2.5)	2800	HP	0.2	G/KWH		Tier II diesel engine

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Particulate matter, total (TPM10)	750	HP	0.2	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Particulate matter, total (TPM2.5)	750	HP	0.2	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Particulate matter, total (TPM10)	3600	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Particulate matter, total (TPM2.5)	3600	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Particulate matter, total (TPM10)	500	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Particulate matter, total (TPM2.5)	500	HP	0.15	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Particulate matter, total (TPM10)	3000	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Particulate matter, total (TPM2.5)	3000	Horsepower	0.15	G/HP-H		certified engine
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, total (TPM10)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, total (TPM2.5)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, total (TPM10)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, total (TPM2.5)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, total (TPM10)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, total (TPM2.5)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Particulate matter, total (TPM2.5)	1341	HP	0.44	LB/HR	HOURLY MAXIMUM	Use of a certified engine, low sulfur diesel, and limiting non-emergency use to no more than 100 hours per year
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Particulate matter, total (TPM10)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Particulate matter, total (TPM2.5)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Particulate matter, total (TPM10)	2922	hp (each)	0.2	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Particulate matter, total (TPM2.5)	2922	hp (each)	0.2	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Particulate matter, total (TPM10)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Particulate matter, total (TPM2.5)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Particulate matter, total (TPM10)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Particulate matter, total (TPM2.5)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Particulate matter, total (TPM10)	0		0			Complying with 40 CFR 60 Subpart IIII
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Particulate matter, total (TPM10)	634	kW	0.3	G/HP-H		Good combustion and operating practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Particulate matter, total (TPM2.5)	634	kW	0.3	G/HP-H		Good combustion and operating practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Particulate matter, total (TPM10)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Particulate matter, total (TPM10)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Particulate matter, total (TPM2.5)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Particulate matter, total (TPM10)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Particulate matter, total (TPM2.5)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Particulate matter, total (TPM10)	575	hp	0.23	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Particulate matter, total (TPM2.5)	575	hp	0.23	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Particulate matter, total (TPM10)	2937	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Particulate matter, total (TPM2.5)	2937	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII (Tier 2 non-road engines) standards, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Particulate matter, total (TPM2.5)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Particulate matter, total (TPM10)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Particulate matter, total (TPM2.5)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII, and limiting non-emergency operation to no more than 100 hours per year
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Particulate matter, total (TPM10)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII, and limiting non-emergency operation to no more than 100 hours per year
*LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Particulate matter, total (TPM10)	3634	horsepower	1.19	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Particulate matter, total (TPM2.5)	3634	horsepower	1.19	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM2.5)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM10)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM2.5)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM10)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, total (TPM10)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, total (TPM2.5)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation

Table D-7.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, total (TPM2.5)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Particulate matter, total (TPM10)	500	H/YR	0.15	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Particulate matter, total (TPM2.5)	500	H/YR	0.15	G/HP H		Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, total (TPM10)	500	H/YR	0.15	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, total (TPM2.5)	500	H/YR	0.15	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Particulate matter, total (TPM10)	2220	HP	1.1	LB	HR	
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Particulate matter, total (TPM2.5)	2220	HP	1.1	LB	HR	
WI-0294	CARDINAL FG COMPANY	P10- Diesel emergency Generator	08/26/2019	Particulate matter, total (TPM2.5)	0		0.05	G/BHP-H		
WI-0294	CARDINAL FG COMPANY	P10- Diesel emergency Generator	08/26/2019	Particulate matter, total (TPM10)	0		0.05	G/BHP-H		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Particulate matter, total (TPM10)	1490	HP	0.15	G/HP-H		Limited to operate 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Particulate matter, total (TPM2.5)	1490	HP	0.15	G/HP-H		Limited to operate 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.

Table D-7.6 Summary of H_2SO_4 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	1529	HP	3.3	X10-4 LB/H		Ultra low sulfur diesel fuel
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	1860	HP	7.3	X10-4 LB/MMBTU		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	2206	HP	0.0016	LB/H		Low sulfur fuel
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	2346	HP	5.1	X10-4 LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	2947	HP	6.4	X10-4 LB/H		Ultra low sulfur diesel fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	700	HP	5.4	X10-4 LB/H		Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Sulfuric Acid (mist, vapors, etc)	2	MW	15	PPM	FUEL SUPPLIER RECORDS OR TEST DATA	Good combustion practices, low sulfur fuel.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Sulfuric Acid (mist, vapors, etc)	1100	KW	2.19	X10-3 LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	1529	HP	3.3	X10-4 LB/H		Ultra low sulfur diesel fuel
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Sulfuric Acid (mist, vapors, etc)	420	brake hp	0.0002	LB PER MMBTU		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Sulfuric Acid (mist, vapors, etc)	0		0.0006	G/HP-HR		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Sulfuric Acid (mist, vapors, etc)	0		0.0007	GM/HP-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Sulfuric Acid (mist, vapors, etc)	1250	kW	0			Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Sulfuric Acid (mist, vapors, etc)	2206	HP	3.4	X10-3 LB/H		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	H/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-7.6 Summary of H_2SO_4 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	H/YR	0.0001	LB/MMBTU		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	1490	HP	0			Operation limited to 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and permittee shall operate and maintain generator according to the manufacturer's recommendations.

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	1529	HP	445	T/YR	PER ROLLING 12 MONTH PERIOD	state of the art combustion design
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	1860	HP	109.2	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design and proper maintenance and operation
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	2206	HP	116.8	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	2346	HP	683	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Carbon Dioxide Equivalent (CO_2e)	2682	HP	163.6	LB/MMBTU		Equipment design and maintenance requirements
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	2947	HP	858	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	3353	HP	200	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Carbon Dioxide Equivalent (CO_2e)	5000	HP	1289	T/YR	PER ROLLING 12 MONTH PERIOD	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Diesel-Fired Emergency Fire Pump (P36)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	510	HP	200	H/Y	IN ANY CONSECUTIVE 12-MONTH PERIOD	
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	700	HP	40.1	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO. ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	1500	HP	406	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Carbon Dioxide Equivalent (CO_2e)	22.68	MMBTU/H	928	T/YR	12-MO. ROLLING TIME PERIOD	Good combustion practices
*MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Carbon Dioxide Equivalent (CO_2e)	22.68	MMBTU/H	928	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	6000	HP	1590	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	2	MW	161	T/YR	12-MO ROLLING TIME PERIOD	Energy efficient design.

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Carbon Dioxide Equivalent (CO_2e)	19.04	MMBTU/HR	163.61	LB/MMBTU		
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	920	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	700	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Carbon Dioxide Equivalent (CO_2e)	1100	KW	474	T/YR	PER ROLLING 12 MONTH PERIOD	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	1529	HP	445	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Carbon Dioxide Equivalent (CO_2e)	27.9	Gal/hr	163.6	LB/MMBTU	3-HOURS	Good Combustion Practices; Limited Operation;
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Carbon Dioxide Equivalent (CO_2e)	186.6	gph	163.6	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices and limit operation to 500 hours per year
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	4474.2	KW	590	T/YR	12-MO ROLLING TIME PERIOD	low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	4474.2	KW	590	T/YR	12-MO ROLLING TIME PERIOD	low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Carbon Dioxide Equivalent (CO_2e)	2015.7	HP	2416	LB/H		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	420	brake hp	123	TONS PER YEAR		
*IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	2012	hp	625	TONS PER YEAR		
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	56	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	56	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	56	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	209	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	590	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	70	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	223	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	209	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
IL-0130	JACKSON ENERGY CENTER	Emergency Engine	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	1500	kW	225	TONS/YEAR		
*LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	650	horsepower	37	TPY		Compliance with NSPS Subpart IIII
*LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	1474	horsepower	84	TPY		Compliance with NSPS Subpart IIII
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	Emergency Engine Generators	09/11/2015	Carbon Dioxide Equivalent (CO_2e)	750	hp	40	HR/YR		Equipment specifications & work practices - Good combustion practices and limited operational hours
*AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good combustion practices

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	0		44	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	0		14	TPY	12-MONTH ROLLING BASIS	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	2695	hp	2332	TONS/YEAR	COMBINED	
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	5364	HP	1481	T/YR	ANNUAL TOTAL	Good Combustion of Practices and Good Operation and Maintenance Practices
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	80	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	0		81	TONS	12-MONTH ROLLING BASIS	
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	143.5	MMBtu/hr	1299630	TPY (ULSD)		Good Cumbustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	1500	kWe	2781	TPY	YEARLY	Good Combustion Practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	1100	KW	444	T/YR	12-MO ROLL. TIME PERIOD; EACH ENGINE	
IL-0129	CPV THREE RIVERS ENERGY CENTER	Emergency Engines	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	1250	kW	508	TONS/YEAR		
OH-0379	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	3131	HP	3632	LB/H		Tier IV engine Good combustion practices
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Carbon Dioxide Equivalent (CO_2e)	2206	HP	120	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	610	hp	565	TONS/YEAR	COMBINED	
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	891	hp	7194	TONS/YEAR	COMBINED	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			good combustion/operating/maintenance practices
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Combustion Practices
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Carbon Dioxide Equivalent (CO_2e)	3634	Horsepower	163	LB/MMBTU		
*IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Carbon Dioxide Equivalent (CO_2e)	3985	hp	160	TONS/YEAR		
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Carbon Dioxide Equivalent (CO2e)	2800	HP	811	TONS	12 CONSECUTIVE MONTHS	Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Carbon Dioxide Equivalent (CO_2e)	750	HP	217	TONS	12 CONSECUTIVE MONTHS	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Carbon Dioxide Equivalent (CO_2e)	3600	HP	1044	TON/YR	TWELVE CONSECUTIVE MONTH PERIOD	
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Carbon Dioxide Equivalent (CO_2e)	500	HP	527.4	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	3000	Horsepower	163.6	LB/MMBTU		Good engineering design and manufacturer's recommended operating and maintenance procedures.
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (400 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	619	HP	180	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (1000 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	1000	kW	389	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
*IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (2000 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	2000	kW	778	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
*IN-0371	WABASH VALLEY RESOURCES, LLC	Ammonia Plant Emergency Generator	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	500	kW	219	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Carbon Dioxide Equivalent (CO_2e)	1341	HP	77	TPY	ANNUAL MAXIMUM	
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Carbon Dioxide Equivalent (CO_2e)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Carbon Dioxide Equivalent (CO_2e)	2922	hp (each)	0			
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Carbon Dioxide Equivalent (CO_2e)	2584	HP	0			Good combustion practices

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	3353	hp	0			good combustion practices
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Carbon Dioxide Equivalent (CO_2e)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	634	kW	44	T/YR	ANNUAL TOTAL	Good Combustion Practices and Good Operation and Maintenance Practices.
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	550	hp	0			Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Carbon Dioxide Equivalent (CO_2e)	575	hp	33	T/YR		Compliance with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	2937	hp	74.21	KG/MM BTU		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Carbon Dioxide Equivalent (CO_2e)	670.5	horsepower	0			Use of good combustion practices and compliance with NSPS Subpart IIII
*LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Carbon Dioxide Equivalent (CO_2e)	670.5	horsepower	0			Use of good combustion practices, compliance with NSPS Subpart IIII
TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Carbon Dioxide Equivalent (CO_2e)	0		72.16	T/YR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.

Table D-7.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Carbon Dioxide Equivalent (CO_2e)	18.7	MMBTU/HR	0			GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	981	T/YR	12 MO ROLLING TOTAL	use of S15 ULSD and high efficiency design and operation
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	1203	T/YR	12 MO ROLLING TOTAL	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Carbon Dioxide Equivalent (CO_2e)	2220	HP	2.543	LB	HR	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	1490	HP	0			Certified to at least meet EPA's criteria for Tier 2 reciprocating internal combustion engines and the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations.

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Nitrogen Oxides (NO_x)	490	hp	4.8	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Nitrogen Oxides (NO_x)	98	hp	5.6	GRAMS/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Nitrogen Oxides (NO_x)	2.7	MMBTU/H	4.41	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	252	hp	3.7	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Nitrogen Oxides (NO_x)	19.4	gph	3.6	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Nitrogen Oxides (NO_x)	2.7	MMBtu/hr	4.41	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Nitrogen Oxides (NO_x)	14.6	Gal/hr	0.45	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Nitrogen Oxides (NO_x)	0		4.86	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Nitrogen Oxides (NO_x)	1073	bhp	2	G/KW-HR		Good operating practices.

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Nitrogen Oxides (NO_x)	0		3.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Nitrogen Oxides (NO_x)	0		14.06	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Nitrogen Oxides (NO_x)	0		14.06	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Nitrogen Oxides (NO_x)	29	MMBTU/H	4	G / KWH	NMHC + NOX (SUBPART IIII)	Low-emitting fuel and certified engine
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Nitrogen Oxides (NO_x)	8700	gal/year	4	G/KW-HR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Nitrogen Oxides (NO_x)	2.46	MMBtu/hour	4	G/KW-HOUR	NMHC + NOX STANDARD	
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Nitrogen Oxides (NO_x)	320	horsepower	4	GRAMS	KILOWATT-HOUR	
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Nitrogen Oxides (NO_x)	369	hp	4	G/KW-HR	3-HR AVG	

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Nitrogen Oxides (NO_x)	0		9.5	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Nitrogen Oxides (NO_x)	150	hp	14.06	G/HP-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Nitrogen Oxides (NO_x)	250	hp	9.2	G/KW-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Nitrogen Oxides (NO_x)	500	Horsepower	3	G/HP-HR		certified engine
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Nitrogen Oxides (NO_x)	197	HP	3	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	260	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	190	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	440	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	190	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	61	HP	3.5	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Nitrogen Oxides (NO_x)	350	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Nitrogen Oxides (NO_x)	288	hp (each)	3	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Nitrogen Oxides (NO_x)	282	HP	1.87	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Nitrogen Oxides (NO_x)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Nitrogen Oxides (NO_x)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Nitrogen Oxides (NO_x)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Nitrogen Oxides (NO_x)	375	HP	4	G/KW-H		Good combustion practices and NSPS IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Nitrogen Oxides (NO_x)	300	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Nitrogen Oxides (NO_x)	0		4	G/KW-HR	NMEHC + NOX	Compliance with 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Nitrogen Oxides (NO_x)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
*LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Nitrogen Oxides (NO_x)	1.1	MM BTU/hr	1.15	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Nitrogen Oxides (NO_x)	450	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Nitrogen Oxides (NO_x)	439	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Nitrogen Oxides (NO_x)	180	hp	2.98	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Nitrogen Oxides (NO_x)	375	hp	4.41	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Nitrogen Oxides (NO_x)	300	hp	0.4	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII.
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Nitrogen Oxides (NO_x)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Nitrogen Oxides (NO_x)	355	hp	3	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Nitrogen Oxides (NO_x)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Nitrogen Oxides (NO_x)	422	horsepower	3.96	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Nitrogen Oxides (NO_x)	422	horsepower	3.96	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Nitrogen Oxides (NO_x)	237	horsepower	1.49	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Nitrogen Oxides (NO_x)	1490	HP	6.4	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Nitrogen Oxides (NO_x)	1.66	MMBTU/H	3	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Nitrogen Oxides (NO_x)	500	H/YR	3	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Nitrogen Oxides (NO_x)	300	HP	3	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Nitrogen Oxides (NO_x)	300	HP	3	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0434	FLAT ROCK ASSEMBLY PLANT	EUFIREPUMPENGS (2 emergency fire pump engines)	03/22/2018	Nitrogen Oxides (NO_x)	250	BHP	3	G/B-HP-H	HOURLY; EACH ENGINE (NMHC+NOX)	Good combustion practices.
MI-0434	FLAT ROCK ASSEMBLY PLANT	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	03/22/2018	Nitrogen Oxides (NO_x)	500	KW	4	G/KW-H	HOURLY; NMHC+NOX	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Nitrogen Oxides (NO_x)	399	BHP	4	G/KW-H	HOURLY	State of the art combustion design.

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Nitrogen Oxides (NO_x)	1.66	MMBTU/H	3	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Nitrogen Oxides (NO_x)	300	HP	3	G/B-HP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Nitrogen Oxides (NO_x)	300	HP	3	G/B-HP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Nitrogen Oxides (NO_x)	2.5	MMBTU/H	3	G/HP-H	HOURLY	Good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Nitrogen Oxides (NO_x)	510	hp	2.38	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Nitrogen Oxides (NO_x)	260	HP	1.72	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Nitrogen Oxides (NO_x)	140	HP	0.81	LB/H		State-of-the-art combustion design

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Nitrogen Oxides (NO_x)	311	HP	1.79	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Nitrogen Oxides (NO_x)	460	HP	0.3	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Nitrogen Oxides (NO_x)	300	HP	1.97	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Nitrogen Oxides (NO_x)	300	HP	1.97	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Nitrogen Oxides (NO_x)	410	HP	2.7	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Nitrogen Oxides (NO_x)	250	HP	1.6	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Nitrogen Oxides (NO_x)	320	HP	2.12	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Nitrogen Oxides (NO_x)	402	HP	2.64	LB/H	SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Nitrogen Oxides (NO_x)	158	HP	0.104	LB/H		Tier IV engine□ Tier IV NSPS standards certified by engine manufacturer.
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Nitrogen Oxides (NO_x)	275	HP	4	G/KW-H	4.0 GRAMS NOX + NMHC/KW-HR	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Nitrogen Oxides (NO_x)	225	HP	0.15	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Nitrogen Oxides (NO_x)	125	HP	0.08	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Nitrogen Oxides (NO_x)	100	HP	0.07	LB/H		Good combustion practices to meet Tier IV emissions
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Nitrogen Oxides (NO_x)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Nitrogen Oxides (NO_x)	214	kW	0.4	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Nitrogen Oxides (NO_x)	0		0			Tier 4 exhaust emission standards specified at 40 CFR Â§ 1039.101(b)
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Nitrogen Oxides (NO_x)	74	KW	100	HR/YR		Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Nitrogen Oxides (NO_x)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€“ Diesel Powered Emergency Generator	06/05/2015	Nitrogen Oxides (NO_x)	0		5.9	LB/HR		Expected NOx emission without controls are 0.59 tons/year and 5.9 pounds/hour. Given this low rate of NOx emissions, due to the 200 hour/year operational limitation, the Department believes, based on engineering judgment, that controls are not economically feasible for this unit. Thus, the RICE MACT remains the only control option.
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Nitrogen Oxides (NO_x)	0.22	mmBTU/hr	4.7	G/KWH		Good Combustion Practices
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Nitrogen Oxides (NO_x)	282	HP	3	G/HP-H		Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Nitrogen Oxides (NO_x)	290	HP	3.64	LB/H		Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Nitrogen Oxides (NO_x)	251	HP	0			
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		

Table D-8.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Nitrogen Oxides (NO_x)	1.27	mmBtu/hr	0			
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Nitrogen Oxides (NO_x)	0		5.9	LB/HR		
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Nitrogen Oxides (NO_x)	0.22	mmBTU/hr	4.7	G/KWH		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Nitrogen Oxides (NO_x)	282	HP	3	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Nitrogen Oxides (NO_x)	290	HP	3.64	LB/H		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Nitrogen Oxides (NO_x)	251	HP	0			

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Carbon Monoxide	490	hp	2.6	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Carbon Monoxide	98	hp	3.7	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Carbon Monoxide	102	hp	3.7	GRAMS/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Carbon Monoxide	2.7	MMBTU/H	0.95	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Carbon Monoxide	252	hp	3.3	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Carbon Monoxide	19.4	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Carbon Monoxide	2.7	MMBtu/hr	0.95	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Carbon Monoxide	14.6	Gal/hr	3.3	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Carbon Monoxide	0		3.5	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Carbon Monoxide	1073	bhp	4	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Carbon Monoxide	0		0.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Carbon Monoxide	0		3.03	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Carbon Monoxide	0		3.03	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Carbon Monoxide	29	MMBTU/H	3.5	G / KWH		Low-emitting fuel and certified engine
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	One 422-hp emergency fire pump engine	03/09/2016	Carbon Monoxide	0		3.5	G / KW-HR		Use of clean engine technology

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0363	DANIA BEACH ENERGY CENTER	Emergency Fire Pump Engine (422 hp)	12/04/2017	Carbon Monoxide	0		3.5	G / KWH		Certified engine
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Carbon Monoxide	8700	gal/year	3.5	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Carbon Monoxide	2.46	MMBtu/hour	3.5	G/KW-HOUR		
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Carbon Monoxide	0		0			
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Carbon Monoxide	420	horsepower	3.5	G/KW-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Carbon Monoxide	320	horsepower	3.5	GRAMS	KILOWATT-HOUR	
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Carbon Monoxide	369	hp	3.5	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Carbon Monoxide	0		2.01	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Carbon Monoxide	150	hp	3.08	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Carbon Monoxide	250	hp	3.08	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Carbon Monoxide	500	Horsepower	2.61	G/HP-HR		oxidation catalyst and certified engine
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Carbon Monoxide	260	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Carbon Monoxide	190	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Carbon Monoxide	440	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Carbon Monoxide	190	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Carbon Monoxide	61	HP	3.73	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Carbon Monoxide	350	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Carbon Monoxide	460	horsepower	3.18	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Carbon Monoxide	225	horsepower	1.55	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Carbon Monoxide	225	horsepower	1.55	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Carbon Monoxide	288	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Carbon Monoxide	282	HP	1.62	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Carbon Monoxide	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Carbon Monoxide	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Carbon Monoxide	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Carbon Monoxide	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Carbon Monoxide	375	HP	3.5			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Carbon Monoxide	300	HP	3.5			Compliance with 40 CFR 60 Subpart IIII
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 -	01/19/2021	Carbon Monoxide	0		3.5	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Carbon Monoxide	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
*LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Carbon Monoxide	1.1	MM BTU/hr	0.4	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Carbon Monoxide	450	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Carbon Monoxide	439	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Carbon Monoxide	180	hp	3.5	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Carbon Monoxide	375	hp	0.95	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Carbon Monoxide	300	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Carbon Monoxide	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Carbon Monoxide	355	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044,	04/29/2022	Carbon Monoxide	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Carbon Monoxide	422	horsepower	3.44	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Carbon Monoxide	422	horsepower	3.44	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Carbon Monoxide	237	horsepower	0.5	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Carbon Monoxide	1490	HP	3.5	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Carbon Monoxide	305	HP	3.5	G/KW-H		USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Carbon Monoxide	1.66	MMBTU/H	2.6	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG. TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Carbon Monoxide	500	H/YR	3.7	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Carbon Monoxide	300	HP	2.6	G/BPH-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Carbon Monoxide	300	HP	2.6	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Carbon Monoxide	399	BHP	3.5	G/KW-H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices.
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Carbon Monoxide	1.66	MMBTU/H	2.6	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Carbon Monoxide	300	HP	2.6	G/B-HP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Carbon Monoxide	300	HP	2.6	G/B-HP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Carbon Monoxide	100	H/YR	1.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Carbon Monoxide	0	100 H/YR	11.6	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation (<= 100 H/YR)

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Carbon Monoxide	100	H/YR	1.87	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Carbon Monoxide	460	hp	0.53	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Carbon Monoxide	260	HP	0.69	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Carbon Monoxide	140	HP	1.15	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Carbon Monoxide	311	HP	1.79	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Carbon Monoxide	460	HP	2.6	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Carbon Monoxide	300	HP	1.73	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Carbon Monoxide	300	HP	1.73	LB/H		state of the art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Carbon Monoxide	410	HP	2.36	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Carbon Monoxide	250	HP	1.4	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Carbon Monoxide	320	HP	1.83	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Carbon Monoxide	402	HP	2.31	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ€™s operating manual
OH-0383	PETMIN USA INCORPORATED	Black Start Generator (P007)	07/17/2020	Carbon Monoxide	158	HP	0.0644	T/YR		Tier IV engine Good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Carbon Monoxide	275	HP	3.5	G/KW-H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Carbon Monoxide	225	HP	1.29	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Carbon Monoxide	125	HP	1.03	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Carbon Monoxide	100	HP	0.83	LB/H		Good combustion practices to meet Tier IV emissions
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Carbon Monoxide	15	gal/hr	0.5	GM/HP-HR		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Fire Pump Engine	09/02/2016	Carbon Monoxide	0		2.61	G/BHP-HR		
*PA-0326	SHELL POLYMERS MONACA SITE	Emergency Generator Parking Garage	02/18/2021	Carbon Monoxide	0		0.5	G	HP-HR	The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*PA-0326	SHELL POLYMERS MONACA SITE	Emergency GeneratorTelecom Hut & Tower	02/18/2021	Carbon Monoxide	0		0.5	G	HP-HR	The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Carbon Monoxide	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Carbon Monoxide	0		0.0068	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Carbon Monoxide	214	kW	3.58	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Carbon Monoxide	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
TX-0889	SWEENY OLD OCEAN FACILITIES	Emergency Generator Engines	08/08/2020	Carbon Monoxide	0		100	HR/YR		Good combustion practices and limited hours of operation
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Carbon Monoxide	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Monoxide	500	HR/YR	2.6	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-8.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Monoxide	500	HR/YR	2.6	G/HP-H		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Carbon Monoxide	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Carbon Monoxide	0.22	mmBTU/hr	5	G/KWH		Good Combustion Practices
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Monoxide	282	HP	2.6	G/HP-H		Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Carbon Monoxide	290	HP	0.33	LB/H		Good combustion practices
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Carbon Monoxide	251	HP	1.44	LB/H		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Monoxide	500	HR/YR	2.6	G/HP-H		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Carbon Monoxide	1.27	mmBtu/hr	0			
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Carbon Monoxide	0.22	mmBTU/hr	5	G/KWH		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Monoxide	282	HP	2.6	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Carbon Monoxide	290	HP	0.33	LB/H		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Carbon Monoxide	251	HP	1.44	LB/H		

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	490	hp	0.0025	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	98	hp	0.0025	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	102	hp	0.0025	LB/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Volatile Organic Compounds (VOC)	2.7	MMBTU/H	0.36	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Volatile Organic Compounds (VOC)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Volatile Organic Compounds (VOC)	2.7	MMBtu/hr	0.36	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Volatile Organic Compounds (VOC)	14.6	Gal/hr	0.22	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Volatile Organic Compounds (VOC)	0		1.55	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Volatile Organic Compounds (VOC)	1073	bhp	1	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Volatile Organic Compounds (VOC)	0		0.13	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Volatile Organic Compounds (VOC)	0		1.12	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Volatile Organic Compounds (VOC)	369	hp	4	G/KW-HR	3-HR AVG	

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Volatile Organic Compounds (VOC)	0		0.05	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Volatile Organic Compounds (VOC)	150	hp	1.134	G/HP-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Volatile Organic Compounds (VOC)	250	hp	1.134	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Volatile Organic Compounds (VOC)	500	Horsepower	1.13	G/HP-HR		certified engine
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Volatile Organic Compounds (VOC)	197	HP	1.14	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	260	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	440	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	61	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Volatile Organic Compounds (VOC)	288	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Volatile Organic Compounds (VOC)	282	HP	1.87	LB/H	HOURLY MAXIMUM	Good combustion practices
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Volatile Organic Compounds (VOC)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Volatile Organic Compounds (VOC)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Volatile Organic Compounds (VOC)	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Volatile Organic Compounds (VOC)	375	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Volatile Organic Compounds (VOC)	300	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Volatile Organic Compounds (VOC)	0		4	G/KW-HR	NMEHC + NOX	Compliance with 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0366	HOLDEN WOOD PRODUCTS MILL	Fire Pump, Sawmill Emergency, and Planer Mill Emergency Generator Engines	02/03/2021	Volatile Organic Compounds (VOC)	0		804.6	HP		Good Combustion Practices and Compliance with NSPS 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Volatile Organic Compounds (VOC)	300	hp	0.19	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII
*LA-0387	TAYLOR SAWMILL	Firewater Pump Engine (FIR)	04/12/2022	Volatile Organic Compounds (VOC)	274	horsepower	0.02	TPY		Compliance with 40 CFR 60 Subpart IIII
LA-0390	DERIDDER SAWMILL	ENG1 - Emergency Fire Water Pump	05/10/2022	Volatile Organic Compounds (VOC)	500	horsepower	1.85	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Volatile Organic Compounds (VOC)	355	hp	3	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Volatile Organic Compounds (VOC)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Volatile Organic Compounds (VOC)	422	horsepower	1.47	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Volatile Organic Compounds (VOC)	422	horsepower	1.47	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Volatile Organic Compounds (VOC)	237	horsepower	0.61	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Volatile Organic Compounds (VOC)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Volatile Organic Compounds (VOC)	1.66	MMBTU/H	0.64	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Volatile Organic Compounds (VOC)	500	H/YR	0.47	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Volatile Organic Compounds (VOC)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good Combustion Practices
*NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Volatile Organic Compounds (VOC)	510	hp	0.62	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Volatile Organic Compounds (VOC)	140	HP	0.11	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Volatile Organic Compounds (VOC)	311	HP	0.25	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Volatile Organic Compounds (VOC)	460	HP	0.14	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Volatile Organic Compounds (VOC)	300	HP	0.24	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Volatile Organic Compounds (VOC)	300	HP	0.24	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Volatile Organic Compounds (VOC)	410	HP	2.7	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Volatile Organic Compounds (VOC)	320	HP	2.12	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Volatile Organic Compounds (VOC)	402	HP	2.64	LB/H	SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Volatile Organic Compounds (VOC)	275	HP	0.7	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OK-0164	MIDWEST CITY AIR DEPOT	Diesel-Fueled Fire Pump Engines	01/08/2015	Volatile Organic Compounds (VOC)	300	HP	0.15	GRAMS PER HP-HR	TOTAL FOR 3 ENGINES.	1. Good Combustion Practices.
OK-0175	WILDHORSE TERMINAL	Emergency Use Engine less than or equal to 500 HP	06/29/2017	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices, certified to meet EPA Tier 3 engine standards. Gen-1, FP-1, and FP-2 shall be limited to operate no more than 500 hr/yr.
OK-0176	BPV GATHERING AND MARKETING CUSHING STATION	Emergency Generator	07/19/2017	Volatile Organic Compounds (VOC)	400	HP	217.24	TONS/YEAR/FACILITY	12-MONTH	Equipped with non-resettable hour meter. Fired with ultra-low sulfur diesel fuel (0.015 % or less by wt. sulfur.
OK-0177	CUSHING SOUTH TANK FARM	Emergency use engine & or = 500 hp	01/04/2018	Volatile Organic Compounds (VOC)	0		1	GM/HP-HR		Good combustion practices, certified to meet EPA Tier III engine standards. Limited to operate no more than 500 hr/yr.
OK-0181	WILDHORSE TERMINAL	EMERGENCY USE ENGINES & 500 HP	09/11/2019	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good Combustion Practices. Certified to meet EPA Tier 3 engine standards. Gen-1 and FP-1 shall be limited to operate not more than 500 hours per year. SP-1 shall be limited to operate not more than 876 hours per year.
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Volatile Organic Compounds (VOC)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Volatile Organic Compounds (VOC)	0		0.0025	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Volatile Organic Compounds (VOC)	214	kW	0.19	G/KW	HR	Meets EPA Tier 4 requirements
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Volatile Organic Compounds (VOC)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Volatile Organic Compounds (VOC)	500	HR/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Volatile Organic Compounds (VOC)	500	HR/YR	0.11	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Volatile Organic Compounds (VOC)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	EG8 â€“ Diesel Emergency Generator	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with NSPS Standards under 40 CFR Part 60 Subpart IIII
WI-0292	GREEN BAY PACKAGING INC. â€"MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Volatile Organic Compounds (VOC)	0		200	HOURS	12-MONTH PERIOD	Hours of Operation
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Volatile Organic Compounds (VOC)	282	HP	1.1	G/HP-H		Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Volatile Organic Compounds (VOC)	290	HP	0.26	LB/H		Good combustion practices
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Volatile Organic Compounds (VOC)	251	HP	0.17	LB/H		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Volatile Organic Compounds (VOC)	500	HR/YR	0.11	G/HP-HR		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Volatile Organic Compounds (VOC)	1.27	mmBtu/hr	0			

Table D-8.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	EG8 Diesel Emergency Generator	10/02/2017	Volatile Organic Compounds (VOC)	0		0			
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Volatile Organic Compounds (VOC)	0		200	HOURS	12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Volatile Organic Compounds (VOC)	282	HP	1.1	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Volatile Organic Compounds (VOC)	290	HP	0.26	LB/H		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Volatile Organic Compounds (VOC)	251	HP	0.17	LB/H		

Table D-8.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Particulate matter, filterable (FPM10)	490	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	490	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Particulate matter, filterable (FPM10)	98	hp	0.3	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	98	hp	0.3	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Particulate matter, filterable(FPM10)	102	hp	0.22	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	102	hp	0.22	GRAMS/HP-H		
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, filterable (FPM)	1073	bhp	0.25	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, filterable (FPM)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, filterable (FPM)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0363	DANIA BEACH ENERGY CENTER	Emergency Fire Pump Engine (422 hp)	12/04/2017	Particulate matter, filterable (FPM)	0		0.2	G / KWH		Certified engine
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Particulate matter, filterable (FPM)	8700	gal/year	0.2	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Particulate matter, filterable (FPM)	0		0.16	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM)	150	hp	1.34	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM10)	150	hp	1.34	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM)	250	hp	0.54	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM10)	250	hp	1.34	G/KW-HR		
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-8.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, filterable (FPM)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Particulate matter, filterable (FPM10)	282	HP	0.09	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Particulate matter, filterable (FPM2.5)	282	HP	0.09	LB/H	HOURLY MAXIMUM	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Particulate matter, filterable (FPM10)	0		0.2	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Particulate matter, filterable (FPM2.5)	0		0.2	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Particulate matter, filterable (FPM10)	0		0			Comply with standards of 40 CFR 60 Subpart IIII, limit operation to <= 100 hrs/yr
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Particulate matter, filterable (FPM2.5)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, filterable (FPM)	1490	HP	0.2	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, filterable (FPM)	305	HP	0.2	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, filterable (FPM)	1.66	MMBTU/H	0.15	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices and meeting NSPS Subpart IIII requirements.

Table D-8.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, filterable (FPM)	500	H/YR	0.22	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, filterable (FPM)	300	HP	0.15	G/BHP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, filterable (FPM)	300	HP	0.15	G/BHP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, filterable (FPM)	399	BHP	0.2	G/KW-H	HOURLY	State of the art combustion design
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, filterable (FPM)	1.66	MMBTU/H	0.15	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, filterable (FPM)	300	HP	0.15	G/B-HP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, filterable (FPM)	300	HP	0.15	G/B-HP-H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	emergency engines	05/12/2016	Particulate matter, filterable (FPM)	0		0	G/KW		good operating practices
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, filterable (FPM)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, filterable (FPM)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, filterable (FPM)	100	H/YR	0.108	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Particulate matter, filterable (FPM)	460	hp	0.087	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Particulate matter, filterable (FPM10)	158	HP	5.22	X10-3 LB/H		Tier IV engine Good combustion practices
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Particulate matter, filterable (FPM2.5)	158	HP	5.22	X10-3 LB/H		Tier IV engine Good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, filterable (FPM)	15	gal/hr	0.11	GM/HP-HR		

Table D-8.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Particulate matter, filterable (FPM)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Particulate matter, filterable (FPM2.5)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, filterable (FPM)	500	HR/YR	15	G/HP/HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, filterable (FPM)	500	HR/YR	0.15	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Particulate matter, filterable (FPM2.5)	251	HP	0			
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, filterable (FPM)	500	HR/YR	0.15	G/HP-HR		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Particulate matter, filterable (FPM2.5)	251	HP	0			

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM10)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM2.5)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM10)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM10)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM2.5)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM10)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM2.5)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM10)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM2.5)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM10)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM2.5)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, total (TPM10)	1073	bhp	0.2	G/KW-HR		Good operating practices.
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, total (TPM2.5)	1073	bhp	0.2	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, total (TPM10)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, total < 2.5 Âµ (TPM2.5)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, total (TPM10)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, total (TPM2.5)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM10)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM2.5)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Particulate matter, total (TPM)	29	MMBTU/H	0.2	G / KWH		Low-emitting fuel and certified engine
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	One 422-hp emergency fire pump engine	03/09/2016	Particulate matter, total (TPM)	0		0.2	G / KW-HR		Use of clean fuel
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Particulate matter, total (TPM)	2.46	MMBtu/hour	0.2	G/KW-HOUR		
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Particulate matter, total (TPM)	0		0			

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Particulate matter, total (TPM)	420	horsepower	0.2	G/KW-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Particulate matter, total (TPM)	320	horsepower	0.2	GRAMS	KILOWATT-HOUR	
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Particulate matter, total (TPM10)	369	hp	0.2	G/KW-HR	3-HR AVG	
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Particulate matter, total (TPM2.5)	369	hp	0.2	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Particulate matter, total (TPM10)	0		0.16	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM)	500	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM10)	500	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM2.5)	500	Horsepower	0.15	G/HP-H		certified engine
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM2.5)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM10)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM10)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM2.5)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, total (TPM10)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, total (TPM2.5)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
*LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Particulate matter, total (TPM2.5)	460	horsepower	0.18	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Particulate matter, total (TPM2.5)	225	horsepower	0.09	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Particulate matter, total (TPM2.5)	225	horsepower	0.09	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Particulate matter, total (TPM10)	288	hp (each)	0.15	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Particulate matter, total (TPM2.5)	288	hp (each)	0.15	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Particulate matter, total (TPM10)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Particulate matter, total (TPM2.5)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Particulate matter, total (TPM10)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Particulate matter, total (TPM2.5)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Particulate matter, total (TPM10)	460	hp	0			Complying with 40 CFR 60 Subpart IIII

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Particulate matter, total (TPM2.5)	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Particulate matter, total (TPM10)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Particulate matter, total (TPM2.5)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Particulate matter, total (TPM10)	375	HP	0.2			Compliance with 40 CFR 60 Subpart IIII.
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Particulate matter, total (TPM2.5)	375	HP	0.2			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Particulate matter, total (TPM10)	300	HP	0.2			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Particulate matter, total (TPM2.5)	300	HP	0.2			Compliance with 40 CFR 60 Subpart III
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Particulate matter, total (TPM10)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Particulate matter, total (TPM2.5)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
*LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Particulate matter, total (TPM2.5)	1.1	MM BTU/hr	0.04	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
*LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Particulate matter, total (TPM10)	1.1	MM BTU/hr	0.04	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Particulate matter, total (TPM)	450	hp	0.4	G//HP-HR		Good combustion practices/gaseous fuel burning
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Particulate matter, total (TPM10)	450	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Particulate matter, total (TPM)	439	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Particulate matter, total (TPM10)	439	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Particulate matter, total (TPM)	180	hp	0.2	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Particulate matter, total (TPM10)	180	hp	0.2	G/KW-HR		Good combustion practices/gaseous fuel burning.

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Particulate matter, total (TPM)	375	hp	0.31	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Particulate matter, total (TPM10)	375	hp	0.31	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Particulate matter, total (TPM10)	300	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Particulate matter, total (TPM2.5)	300	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Particulate matter, total (TPM2.5)	0		0			Comply with standards of 40 CFR 60 Subpart IIII Limit operation to <= 100 hrs/yr
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 -	06/13/2019	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 -	06/13/2019	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Particulate matter, total (TPM10)	355	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII standards, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Particulate matter, total (TPM2.5)	355	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044,	04/29/2022	Particulate matter, total (TPM10)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Particulate matter, total (TPM2.5)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Particulate matter, total (TPM10)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Particulate matter, total (TPM2.5)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Particulate matter, total (TPM10)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Particulate matter, total (TPM2.5)	237	horsepower	0.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Particulate matter, total (TPM10)	237	horsepower	0.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Particulate matter, total (TPM10)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Particulate matter, total (TPM2.5)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, total (TPM10)	1490	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, total (TPM2.5)	1490	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AN DGOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, total (TPM10)	305	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, total (TPM2.5)	305	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, total (TPM10)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, total (TPM2.5)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, total (TPM10)	500	H/YR	0.09	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, total (TPM2.5)	500	H/YR	0.09	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, total (TPM10)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, total (TPM2.5)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, total (TPM10)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, total (TPM2.5)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Particulate matter, total (TPM10)	500	h/yr	0.15	G/B-HP-H	HOURLY (EACH INDIVIDUAL EMISSION UNIT)	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Particulate matter, total (TPM2.5)	500	h/yr	0.15	G/B-HP-H	HOURLY (EACH INDIVIDUAL EMISSION UNIT)	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.69	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.69	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Particulate matter, total (TPM)	510	hp	0.15	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, total (TPM10)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, total (TPM2.5)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, total (TPM10)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, total (TPM2.5)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, total (TPM10)	100	H/YR	0.108	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, total (TPM2.5)	100	H/YR	0.108	LB/H		Use of ULSD a clean burning fuel and limited hours of operation
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Particulate matter, total (TPM)	260	HP	0.09	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Particulate matter, total (TPM10)	260	HP	0.09	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Particulate matter, total (TPM2.5)	260	HP	0.09	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Particulate matter, total (TPM10)	140	HP	0.07	LB/H		State-of-the-art combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Particulate matter, total (TPM2.5)	140	HP	0.07	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Particulate matter, total (TPM10)	311	HP	0.1	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Particulate matter, total (TPM2.5)	311	HP	0.1	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Particulate matter, total (TPM10)	460	HP	0.02	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Particulate matter, total (TPM2.5)	460	HP	0.02	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Particulate matter, total (TPM10)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Particulate matter, total (TPM2.5)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Particulate matter, total (TPM10)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Particulate matter, total (TPM2.5)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Particulate matter, total (TPM)	410	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ€™s operating manual.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Particulate matter, total (TPM2.5)	410	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ€™s operating manual.
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Particulate matter, total (TPM10)	250	HP	0.1	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Particulate matter, total (TPM2.5)	250	HP	0.1	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM10)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM2.5)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ€™s operating manual
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM10)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM2.5)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM)	275	HP	0.2	G/KW-H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM10)	275	HP	0.6	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM2.5)	275	HP	0.6	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Particulate matter, total (TPM10)	225	HP	0.02	LB/H	SEE NOTES	Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Particulate matter, total (TPM2.5)	225	HP	0.02	LB/H	SEE NOTES	Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Particulate matter, total (TPM10)	125	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Particulate matter, total (TPM2.5)	125	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Particulate matter, total (TPM10)	100	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Particulate matter, total (TPM2.5)	100	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, total (TPM10)	15	gal/hr	0.11	GM/HP-HR		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, total (TPM2.5)	15	gal/hr	0.11	GM/HP-HR		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Fire Pump Engine	09/02/2016	Particulate matter, total (TPM)	0		0.15	G/BHP-HR		
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM10)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM2.5)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Particulate matter, total (TPM10)	214	kW	0.02	G/KW	HR	Meets EPA Tier 4 requirements
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Particulate matter, total (TPM2.5)	214	kW	0.02	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM)	0		0			Tier 4 exhaust emission standards specified at 40 CFR Â§ 1039.101(b)
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM10)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM2.5)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP-HR		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM10)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM2.5)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM)	0		0.29	LB/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM10)	0		0.29	;B/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM2.5)	0		0.29	LB/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and shall be operated and maintained according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM10)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM2.5)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and shall be operated and maintained according to the manufacturer's recommendations.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM10)	290	HP	0.11	LB/H		Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM)	290	HP	0.11	LB/H		Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight

Table D-8.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP-HR		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP-HR		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM)	1.27	mmBtu/hr	0			
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM10)	1.27	mmBtu/hr	0			
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM2.5)	1.27	mmBtu/hr	0			
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM)	0		0.29	LB/HR		
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM10)	0		0.29	LB/HR		
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM2.5)	0		0.29	LB/HR		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM)	282	HP	0.15	G/HP-H		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM10)	282	HP	0.15	G/HP-H		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM2.5)	282	HP	0.15	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM10)	290	HP	0.11	LB/H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM)	290	HP	0.11	LB/H		

Table D-8.6 Summary of H_2SO_4 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Sulfuric Acid (mist, vapors, etc)	29	MMBTU/H	0.0015	% S IN ULSD	FUEL RECORD KEEPING	Limit in S in fuel
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Sulfuric Acid (mist, vapors, etc)	320	horsepower	0			Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Sulfuric Acid (mist, vapors, etc)	1490	HP	0.007	G/HP-H	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Sulfuric Acid (mist, vapors, etc)	305	HP	0.007	G/HP-H	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Sulfuric Acid (mist, vapors, etc)	399	BHP	15	PPM	FUEL SUPPLIER RECORDS OR TEST DATA	Good combustion practices, low sulfur fuel.
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Sulfuric Acid (mist, vapors, etc)	460	hp	0.0001	LB/MMBTU	1 H	Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Sulfuric Acid (mist, vapors, etc)	260	HP	3.9	X10-4 LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	140	HP	3	X10-5 LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	311	HP	6.7	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	300	HP	6.5	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	300	HP	6.5	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Sulfuric Acid (mist, vapors, etc)	410	HP	0.0015	LB/MMBTU		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	320	HP	7.3	X10-4 LB/MMBTU		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Sulfuric Acid (mist, vapors, etc)	15	gal/hr	0.0006	G/HP-HR		

Table D-8.6 Summary of H_2SO_4 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0.0001	LB/MMBTU		good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Sulfuric Acid (mist, vapors, etc)	1.27	mmBtu/hr	0			Use diesel fuel with sulfur content < 15 ppm
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	282	HP	0			Operation limited to 500 hours/year, operate and maintain according to the manufacturerâ€™s recommendations, and sulfur content of the diesel fuel oil fired may not exceed 15 ppm.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	290	HP	0			Only use diesel fuel oil with a sulfur content of no greater than 0.015% by weight
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0			
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0.0001	LB/MMBTU		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING	Fire pump (process P05)	02/15/2016	Sulfuric Acid (mist, vapors, etc)	1.27	mmBtu/hr	0			
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	282	HP	0			
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	290	HP	0			

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	490	hp	163	TONS/YEAR		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	98	hp	356	TONS/YEAR		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	102	hp	516	TONS/YEAR		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Carbon Dioxide Equivalent (CO_2e)	2.7	MMBTU/H	37.2	TONS/YEAR		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	252	hp	216	TPY (COMBINED)	YEARLY	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Carbon Dioxide Equivalent (CO_2e)	19.4	gph	163.6	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices and limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Carbon Dioxide Equivalent (CO_2e)	2.7	MMBtu/hr	164	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Carbon Dioxide Equivalent (CO_2e)	14.6	Gal/hr	163.6	LB/MMBTU	3-HOURS	Good Combustion Practices; Limited Operation
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	1073	bhp	163	LB/MMBTU		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Operating Practices
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Operating Practices
*AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good combustion practices
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	420	horsepower	241	TONS/YEAR	12-MONTH ROLLING AVERAGE	
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	320	horsepower	92	TONS/YEAR		
*IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Carbon Dioxide Equivalent (CO_2e)	369	hp	25	TONS/YEAR		

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	500	Horsepower	163.6	LB/MMBTU		Good engineering design and manufacturer's recommended operating and maintenance procedures.
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	750	KW	59.5	TONS PER YEAR	12-MONTH ROLLING AVERAGE	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	260	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	440	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	61	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
*LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	460	horsepower	26	Y/YR	ANNUAL MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	225	horsepower	13	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
*LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	225	horsepower	13	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Carbon Dioxide Equivalent (CO_2e)	288	hp (each)	0			
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			Good combustion practices
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Carbon Dioxide Equivalent (CO_2e)	425	hp	0			
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Carbon Dioxide Equivalent (CO_2e)	350	hp	0			
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	460	hp	0			good combustion practices

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Carbon Dioxide Equivalent (CO_2e)	375	HP	28	T/YR		Good Combustion Practices
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	28	T/YR		Good Combustion Practices
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			Energy efficiency measures to minimize the amount of fuel used
*LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Carbon Dioxide Equivalent (CO_2e)	1.1	MM BTU/hr	9	TPY	ANNUAL MAXIMUM	Good combustion practices in order to comply with 40 CFR 60 Subpart IIII
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Good engine design Good work practices
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	355	hp	74.21	KG/MM BTU		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
*LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Carbon Dioxide Equivalent (CO_2e)	200	horsepower	12	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Carbon Dioxide Equivalent (CO_2e)	1.66	MMBTU/H	13.58	T/YR	12 MO. ROLLING TIME PERIOD	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	55.6	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	399	BHP	86	T/YR	12-MO ROLLING TIME PERIOD	Energy efficient design

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Carbon Dioxide Equivalent (CO_2e)	1.66	MMBTU/H	13.58	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	656.2	T/YR	12-MO ROLLING TIME PERIOD	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Carbon Dioxide Equivalent (CO_2e)	460	hp	115	TPY	MO	Good combustion practice and efficient engine design.
OH-0363	NTE OHIO, LLC	Emergency Fire Pump Engine (P003)	11/05/2014	Carbon Dioxide Equivalent (CO_2e)	260	HP	75	T/YR	PER ROLLING 12 MONTH PERIOD	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	140	HP	41	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	311	HP	90	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Carbon Dioxide Equivalent (CO_2e)	460	HP	123	T/YR	PER ROLLING 12 MONTH PERIOD	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	300	HP	87	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	300	HP	87	T/YR	PER ROLLING 12 MONTH PERIOD	State-of-the-art combustion design

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Carbon Dioxide Equivalent (CO_2e)	410	HP	29	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Carbon Dioxide Equivalent (CO_2e)	250	HP	163.6	LB/MMBTU		Equipment design and maintenance requirements
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	320	HP	18.67	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design and proper maintenance and operation
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	402	HP	23	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	158	HP	181.7	LB/H		Tier IV engine Good combustion practices
OH-0383	PETMIN USA INCORPORATED	Black Start Generator (P007)	07/17/2020	Carbon Dioxide Equivalent (CO_2e)	158	HP	9.09	T/YR		Tier IV engine Good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	225	HP	1209	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	125	HP	65	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	100	HP	539	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices
OK-0164	MIDWEST CITY AIR DEPOT	Diesel-Fueled Fire Pump Engines	01/08/2015	Carbon Dioxide Equivalent (CO_2e)	300	HP	44	TONS PER YEAR	TOTAL FOR 3 ENGINES.	1. Good Combustion Practices. 2. Efficient Design.
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	15	gal/hr	9	TON	12-MONTH ROLLING BASIS	
*PA-0326	SHELL POLYMERS MONACA SITE	Emergency Generator Parking Garage	02/18/2021	Carbon Dioxide Equivalent (CO_2e)	0		10	TONS	YEARLY ON 12 MONTH ROLLING	Good Combustion Practices - no feasible control technologies, 10 tons CO2e Year 12 month rolling basis for Parking Garage and Telecom emergency generators combined
*PA-0326	SHELL POLYMERS MONACA SITE	Emergency GeneratorTelecom Hut & Tower	02/18/2021	Carbon Dioxide Equivalent (CO_2e)	0		10	TONS	YEARLY ON 12 MONTH ROLLING	Good Combustion Practices - no feasible control technologies, 10 tons CO2e Year 12 month rolling basis for Parking Garage and Telecom emergency generators combined

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Carbon Dioxide Equivalent (CO2e)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0753	GUADALUPE GENERATING STATION	Fire Water Pump Engine	12/02/2014	Carbon Dioxide Equivalent (CO2e)	1.92	MMBtu/hr (HHV)	15.71	TPY CO2E		
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Carbon Dioxide Equivalent (CO2e)	0		6.79	T/YR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0824	JACKSON COUNTY GENERATING FACILITY	Emergency Diesel-Fired Equipment	06/30/2017	Carbon Dioxide Equivalent (CO2e)	160	HP	13	T/YR		Good operating and maintenance practices, efficient design, and low annual capacity
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Carbon Dioxide Equivalent (CO2e)	214	kW	0			Meets EPA Tier 4 requirements . Fuels with a low carbon density, regular equipment maintenance, the use of efficient equipment and operation limited to less than 100 hr/yr
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Carbon Dioxide Equivalent (CO2e)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
TX-0889	SWEENY OLD OCEAN FACILITIES	Emergency Generator Engines	08/08/2020	Carbon Dioxide Equivalent (CO2e)	0		0			Good combustion practices and limited hours of operation
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Carbon Dioxide Equivalent (CO2e)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Dioxide Equivalent (CO2e)	500	HR/YR	1040	T/YR	12 MO ROLLING TOTAL	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Dioxide Equivalent (CO2e)	500	HR/YR	106	T/YR	12 MO ROLLING TOTAL	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
WI-0292	GREEN BAY PACKAGING INC. â€"MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Carbon Dioxide Equivalent (CO2e)	0		200	HOURS	12-MONTH PERIOD	Hours of Operation

Table D-8.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			Be certified by manufacturer to EPA's criteria for Tier 3 reciprocating internal combustion engines and to the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain according to the manufacturer's recommendations.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Carbon Dioxide Equivalent (CO_2e)	251	HP	309	LB/H		
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	500	HR/YR	1040	T/YR	12 MO ROLLING TOTAL	
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	500	HR/YR	106	T/YR	12 MO ROLLING TOTAL	
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Carbon Dioxide Equivalent (CO_2e)	0		200	HOURS	12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Carbon Dioxide Equivalent (CO_2e)	251	HP	309	LB/H		

Table D-9.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0161	SUN BIO MATERIAL COMPANY	Cooling Towers	09/23/2019	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT LOSS		Drift Eliminators Low TDS
FL-0363	DANIA BEACH ENERGY CENTER	Mechanical draft cooling system	12/04/2017	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Mechanical Draft Auxiliary Cooling System	07/27/2018	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Mechanical Draft Auxiliary Cooling System	06/07/2021	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-01 - Melt Shop ICW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	52000	gal/min	0.36	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-02 - Melt Shop DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	5900	gal/min	0.04	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-03 - Rolling Mill ICW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	8500	gal/min	0.06	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-04 - Rolling Mill DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	22750	gal/min	0.17	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-05 - Rolling Mill Quench/ACC Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	90000	gal/min	0.78	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-06 - Light Plate Quench DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	8000	gal/min	0.06	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-07 - Heavy Plate Quench DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	3000	gal/min	0.02	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-08 - Air Separation Plant Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	14000	gal/min	0.1	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.

Table D-9.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Laminar Cooling Tower - Hot Mill Cells (EP 03-09)	04/19/2021	Particulate matter, filterable (FPM)	35000	gal/min	0.27	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Direct Cooling Tower-Caster & Roughing Mill Cells (EP 03-10)	04/19/2021	Particulate matter, filterable (FPM)	26300	gal/min	0.17	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Melt Shop #2 Cooling Tower (indirect) (EP 03-11)	04/19/2021	Particulate matter, filterable (FPM)	59500	gal/min	0.39	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Cooling Tower (EP 03-12)	04/19/2021	Particulate matter, filterable (FPM)	20000	gal/min	0.14	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Plant Cooling Tower (EP 03-13)	04/19/2021	Particulate matter, filterable (FPM)	15000	gal/min	0.08	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	DCW Auxiliary Cooling Tower (EP 03-14)	04/19/2021	Particulate matter, filterable (FPM)	9250	gal/min	0.06	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 043 - Cooling Tower #1	07/25/2022	Particulate matter, filterable (FPM)	0.15	MMgal/hr	0.013	LB/HR	MONTHLY AVERAGE	Mist Eliminator (0.001% drift loss), Total Dissolved Solids (TDS) concentration limit of 1000 ppm
MI-0427	FILER CITY STATION	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)	11/17/2017	Particulate matter, filterable (FPM)	0		0.0006	%	VENDOR-CERTIFIED MAX. DRIFT RATE	Mist/Drift Eliminators
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUCOOLTOWER (North Plant): Cooling Tower	06/29/2018	Particulate matter, filterable (FPM)	170000	GAL/M	5.59	T/YR	12-MONTH ROLLING TIME PERIOD	High efficiency drift/mist eliminators
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUCOOLTOWER (South Plant): Cooling Tower	06/29/2018	Particulate matter, filterable (FPM)	170000	GAL/M	5.59	T/YR	12-MO ROLLING TIME PERIOD	High efficiency drift/mist eliminators.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUCOOLINGTWR: Cooling Tower	07/16/2018	Particulate matter, filterable (FPM)	0		4.03	LB/H	HOURLY	High efficiency drift/mist eliminators

Table D-9.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Contact Cooling Towers - Melt Shop 2 (P027)	09/27/2019	Particulate matter, filterable (FPM)	2.7	MMGAL/H	1.17	T/YR	PER ROLLING, 12-MONTH PERIOD.	i.use of drift eliminator(s) designed to achieve a 0.001% drift rate; ii.maintenance of a total dissolved solids (TDS) content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop 2 Cooling Tower - 1000 Caster Mold Water Cooling Tower - 800 Tunnel Furnace Cooling Tower - 800 Caster Non-Contact 2 Cooling Tower - 800 Caster Contact 2 Cooling Tower - 1400
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Contact Cooling Towers (P014)	09/27/2019	Particulate matter, filterable (FPM)	6.41	MMGAL/H	8.7	T/YR	PER ROLLING, 12-MONTH PERIOD.	i.use of drift eliminator(s) designed to achieve a 0.003% drift rate; ii.maintenance of a total dissolved solids (TDS) content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop Cooling Tower (501) - 800 Caster Non-Contact Cooling Tower (6 Cell) - 800 Caster Contact Cooling Tower (503) - 1100 Mill Contact Cooling Tower (505) - 2000 Laminar Flow Cooling Tower (506) - 1400
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	Cooling Towers	10/31/2023	Particulate matter, filterable (FPM)	0		0.001	% DRIFT RATE		Drift Eliminator

Table D-9.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	COOLING TOWER	02/06/2020	Particulate matter, filterable (FPM)	0		1200	PPM	TDS	DRIFT ELIMINATORS
*TX-0964	NEDERLAND FACILITY	COOLING TOWERS	10/05/2023	Particulate matter, filterable (FPM)	0		2000	PPMW	TDS	Drift eliminators with 0.001% drift

Table D-9.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Mechanical draft cooling tower	03/09/2016	Particulate matter, total (TPM)	465815	gallons water/min	0			Must have certified drift rate no more than 0.0005%.
FL-0368	NUCOR STEEL FLORIDA FACILITY	Two Cooling Towers	02/14/2019	Particulate matter, total (TPM)	19650	gal/min	0.001	% DRIFT RATE		Drift eliminators
IN-0317	RIVERVIEW ENERGY CORPORATION	Cooling tower EU-6001	06/11/2019	Particulate matter, total (TPM)	32000	GAL/HR	2395	MG/L	TDS IN CIRCULATING WATER	drift eliminator
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Mechanical draft cooling tower	07/14/2015	Particulate matter, total (TPM)	0		0.0005	% DRIFT RATE		high efficiency drift eliminators (integral part of the design)
KS-0040	JOHNS MANVILLE AT MCPHERSON	Cooling Towers	12/03/2019	Particulate matter, total (TPM)	0		0.001	PERCENT	DRIFT RATE FROM EACH TOWERS	Drift Rate Control
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGCOOLTWR	08/21/2019	Particulate matter, total (TPM)	92500	GAL/M	4.1	T/YR	12-MO ROLLING TIME PERIOD	Particulate in water droplets will be controlled with high efficiency drift/mist eliminators.
NE-0059	AGP SOY	Cooling Tower	03/25/2015	Particulate matter, total (TPM)	360000	gal/hr	0.0005	%	DRIFT LOSS	drift loss design specification and TDS concentration limit
*NE-0064	NORFOLK CRUSH, LLC	Cooling Tower	11/21/2022	Particulate matter, total (TPM)	480060	gal/hr	0.0005	%	DRIFT LOSS	There is a drift loss design specification and a TDS concentration limit.
*NE-0068	AG PROCESSING INC - DAVID CITY	Cooling Tower 1	06/27/2023	Particulate matter, total (TPM)	759600	gal/hr	0.0005	%		There is a drift loss design specification with the mist eliminator (CE-8000) and a TDS concentration limit.
*NE-0068	AG PROCESSING INC - DAVID CITY	Cooling Tower 2	06/27/2023	Particulate matter, total (TPM)	303840	gal/hr	0.0005	%		There is a drift loss design specification with the mist eliminator (CE-8001) and a TDS concentration limit.
OH-0363	NTE OHIO, LLC	Cooling Tower (P004)	11/05/2014	Particulate matter, total (TPM)	175000	GAL/M	2.685	LB/H		High efficiency drift eliminators and minimize total dissolved solid (TDS)
OH-0364	OREGON ENERGY CENTER	Cooling Towers #1 & #2 (P009 & P010)	05/20/2015	Particulate matter, total (TPM)	115037	GAL/M	1.48	LB/H		advanced drift eliminators with a drift rate of less than 0.0005 percent and maintain the total dissolved solids (TDS) content of the circulating cooling water at 5,130 mg/L or less as a 24-hour rolling average

Table D-9.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Wet Mechanical Draft Cooling Tower (P003)	11/07/2017	Particulate matter, total (TPM)	120000	GAL/M	6.58	T/YR	PER ROLLING 12 MONTH PERIOD	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and total dissolved solids (TDS) content not to exceed 5,000 mg/l.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Cooling Tower (P011)	12/21/2018	Particulate matter, total (TPM)	13.88	MMGAL/H	5.07	T/YR	PER ROLLING 12 MONTH PERIOD	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.
OH-0387	INTEL OHIO SITE	Cooling Towers: P054 through P178	09/20/2022	Particulate matter, total (TPM)	0		0.0005	%	DRIFT RATE	Drift eliminator
*OH-0391	VALENCIA PROJECT LLC	Cooling Towers (P023, P024, P025)	10/27/2023	Particulate matter, total (TPM)	0		0.05	LB/H	SEE NOTES	A drift eliminator achieving â€œdrift lossâ€ equal to or less than 0.0005 percent
TX-0832	EXXONMOBIL BEAUMONT REFINERY	COOLING TOWERS	01/09/2018	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATOR
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	COOLING TOWER	03/30/2018	Particulate matter, total (TPM)	9864000	GAL/H	0			DRIFT ELIMINATORS
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	COOLING TOWER	03/30/2018	Particulate matter, total (TPM2.5)	9864000	GAL/H	0			DRIFT ELIMINATORS
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	Cooling Tower	09/09/2019	Particulate matter, total (TPM)	0		0.005	% DRIFT		drift eliminators
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	COOLING TOWER	09/09/2019	Particulate matter, total (TPM)	0		6000	PPMW	TDS	DRIFT ELIMINATORS
TX-0873	PORT ARTHUR REFINERY	COOLING TOWER	02/04/2020	Particulate matter, total (TPM)	35000	GPM	0			DRIFT ELIMINATORS
TX-0888	ORANGE POLYETHYLENE PLANT	COOLING TOWERS	04/23/2020	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATORS
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	COOLING TOWER	09/09/2020	Particulate matter, total (TPM)	0		1200	PPMW		Non-contact design and DRIFT ELIMINATORS

Table D-9.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	COOLING TOWER	09/16/2020	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATORS 0.001%
TX-0915	UNIT 5	COOLING TOWER	03/17/2021	Particulate matter, total (TPM)	0		60000	PPM	TDS	Drift eliminators 0.0005%
TX-0922	HOUSTON PLANT - 46307	COOLING TOWER	06/13/2022	Particulate matter, total (TPM)	0		0			Drift eliminators with 0.0005% drift
TX-0930	CENTURION BROWNSVILLE	Cooling Tower	10/19/2021	Particulate matter, total (TPM)	0		0			Drift eliminators required. Maximum drift 0.0005 percent. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.
TX-0931	ROEHM AMERICA BAY CITY SITE	Cooling Tower	12/16/2021	Particulate matter, total (TPM)	0		0			Drift eliminators with 0.001% drift
*TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	COOLING TOWER	05/03/2024	Particulate matter, total (TPM)	0		0			Drift eliminators 0.001% drift
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	COOLING TOWER	03/13/2023	Particulate matter, total (TPM)	13734000	GAL/HR	0			0.001% DRIFT ELIMINATORS
TX-0940	FIBERGLASS MANUFACTURING FACILITY	COOLING TOWER	09/06/2022	Particulate matter, total (TPM)	2175	GAL/MIN	0.001	%		DRIFT ELIMINATOR
*TX-0967	QUAIL RUN CARBON CAPTURE PLANT	COOLING TOWERS	02/05/2024	Particulate matter, total (TPM)	142700	gal/min	0			drift eliminators 0.0005%
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P02A-P & P03A-P Cooling Towers	04/24/2018	Particulate matter, total (TPM)	0		0			Drift Eliminator& Cooling Additive Control System
WI-0311	SUPERIOR REFINING COMPANY LLC	Cooling Tower No.1 (P80)	09/27/2019	Particulate matter, total (TPM)	10000	GPM	0.0005	% CIRCULATION DRIFT		Drift eliminator, cooling additive control system that results in a total dissolved solids (TDS) concentration of not more than 3,000 ppm.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Cooling Tower	11/21/2014	Particulate matter, total (TPM)	159000	gpm	0.72	LB/H		Drift Eliminator

Table D-10.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0084	DONLIN GOLD PROJECT	Fuel Tanks	06/30/2017	Volatile Organic Compounds (VOC)	0		1.7	TPY	YEARLY	Submerged Fill
AK-0085	GAS TREATMENT PLANT	Fuel Tanks	08/13/2020	Volatile Organic Compounds (VOC)	0		0.59	TPY	YEAR	Submerged Fill
AK-0088	LIQUEFACTION PLANT	Three Diesel Storage Tanks	07/07/2022	Volatile Organic Compounds (VOC)	0		0.01	TPY COMBINED		Submerged Fill
FL-0354	LAUDERDALE PLANT	Two 3-million gallon ULSD storage tanks	08/25/2015	Volatile Organic Compounds (VOC)	0		0			Low vapor pressure prevents evaporative losses
IN-0273	ST. JOSEPH ENERGY CENTER	DIESEL STORAGE TANK TK11	06/22/2017	Volatile Organic Compounds (VOC)	650	GALLONS	0			THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.
IN-0273	ST. JOSEPH ENERGY CENTER	DIESEL STORAGE TANK TK50	06/22/2017	Volatile Organic Compounds (VOC)	5000	GALLONS	0			THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.
IN-0318	RIVERVIEW ENERGY CORPORATION	Diesel product tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		2.29	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Residue tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0001	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Vacuum Gas Oil Tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.175	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Diesel fuel tank T17	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0114	TONS	12 CONSECUTIVE MONTHS	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Emergency engine fuel tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0114	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Diesel Storage Tank (EU76)	10/24/2016	Volatile Organic Compounds (VOC)	2000	gallons	0			The diesel storage tank (EU76) shall be equipped with a permanent submerged fill pipe.

Table D-10.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Gasoline Storage Tank (EU75)	10/24/2016	Volatile Organic Compounds (VOC)	2000	Gallon (Capacity)	0			The permittee shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following: i. Minimize gasoline spills; ii. Clean up spills as expeditiously as practicable; iii. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators. The gasoline storage tank (EU75) shall be equipped with a permanent submerged fill pipe.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-02 - Gasoline Storage Tanks #1 & #2	07/23/2020	Volatile Organic Compounds (VOC)	2000	gal combined	0			The gasoline storage tanks (EP 15-02) shall be equipped with a permanent submerged fill pipe.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 044 - Diesel Fuel Storage and Refueling Station	07/25/2022	Volatile Organic Compounds (VOC)	68000	gal/yr	0			Spill & overfill protection, Submerged fill pipes, & Good Work Practices (GWP) Plan
LA-0276	BATON ROUGE JUNCTION FACILITY	Vertical Fixed Roof Tanks 174, 175, 176	12/15/2016	Volatile Organic Compounds (VOC)	0		0			Submerged fill pipes and pressure/vacuum vents
LA-0309	BENTELER STEEL TUBE FACILITY	Gasoline Tank S16	06/04/2015	Volatile Organic Compounds (VOC)	600	gallons	0			Submerged fill pipe
LA-0314	INDORAMA LAKE CHARLES FACILITY	Unleaded Gasoline Tank TK-33	08/03/2016	Volatile Organic Compounds (VOC)	1000	gallons	0			Submerged fill pipe and LAC 33:III.2103
*LA-0399	TEAL JONES-PLAIN DEALING SAW MILL	Small Gasoline and Diesel Tanks	10/31/2022	Volatile Organic Compounds (VOC)	0		0			Light color, fixed roofs, submerged fill/bottom loading, and good operating practice
OK-0177	CUSHING SOUTH TANK FARM	4,000 GALLON SUMP TANK	01/04/2018	Volatile Organic Compounds (VOC)	208000	BBL/YR	0			Submerged fill and good housekeeping, including quarterly inspection requirements in the SPCC plan.
SC-0193	MERCEDES BENZ VANS, LLC	Storage Tank	04/15/2016	Volatile Organic Compounds (VOC)	5000	gal	0			Stage 1 Vapor Control

Table D-10.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	Petroleum Liquids Storage in Fixed Roof Tanks	04/10/2015	Volatile Organic Compounds (VOC)	3.4	MMBbl/yr/tank	15.78	TONS/YR/TANK		Temperature reduced to maintain volatile organic compound (VOC) vapor pressure < 0.5 pounds per square inch actual (psia) at all times.
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Storage Tanks, TK-110, TK-111, TK-112	06/19/2015	Volatile Organic Compounds (VOC)	57960	gal/hr	3.07	LB/HR		Tanks are required to be painted white and be equipped with submerged fill pipes
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Storage Tanks, TK-113, TK-114, and TK-115	06/19/2015	Volatile Organic Compounds (VOC)	47000000	gal/yr/tank	0.85	LB/HR		Tanks are required to be painted white and be equipped with submerged fill pipes
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Petroleum Liquids Storage in Fixed Roof Tanks	11/06/2015	Volatile Organic Compounds (VOC)	47.62	BBL/YR	0.01	T/YR		Tank uses submerged fill and is aluminum in color.
TX-0799	BEAUMONT TERMINAL	Storage Tanks - fixed roof	06/08/2016	Volatile Organic Compounds (VOC)	0		72.5	T/YR		Fixed-roof tanks (EPNs 168, 222, 225, 227,229, 254, 256, 257, 258, 259, 475, and 476) will use submerged fill and have white exterior surfaces. Fuel tanks (EPN DTK01 and GTK01) are horizontal fixed-roof design and will use submerged fill and have white or aluminum exterior surfaces.
TX-0813	ODESSA PETROCHEMICAL PLANT	Petroleum Liquid Storage in Fixed Roof tanks	11/22/2016	Volatile Organic Compounds (VOC)	0		0.01	T/YR		Submerged fill pipe, reflective or white exterior paint.
TX-0840	CORPUS CHRISTI TERMINAL	Heavy oil storage	10/31/2018	Volatile Organic Compounds (VOC)	0		0			1 fixed roof tank has storage of heavy oil (EPN: T-1334) with VP < 0.5 psia, painted white and equipped with submerged fill pipe.
TX-0847	VALERO PORT ARTHUR REFINERY	Coker sludge feed tanks	09/16/2018	Volatile Organic Compounds (VOC)	12000	GAL/HR	100	PPM		NON REGENERATIVE CARBON ADSORBER
TX-0850	CORPUS CHRISTI TERMINAL	Heavy oil storage in fixed roof tank	07/15/2018	Volatile Organic Compounds (VOC)	0		0			Storage of heavy oil (EPN: T-1334) in a fixed roof tank with VP < 0.5 psia, painted white and equipped with submerged fill pipe.
TX-0855	BUCKEYE SOUTH TEXAS GATEWAY TERMINAL	Fixed Roof Tanks	03/13/2019	Volatile Organic Compounds (VOC)	0		0			painted white and equipped with the submerged fill piping.
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FIXED ROOF TANKS	08/29/2019	Volatile Organic Compounds (VOC)	0		0			Painted White with Submerged Fill
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FIXED ROOF TANKS	08/29/2019	Volatile Organic Compounds (VOC)	0		0			Painted White with Submerged Fill
TX-0888	ORANGE POLYETHYLENE PLANT	FIXED ROOF STORAGE TANKS	04/23/2020	Volatile Organic Compounds (VOC)	0		0			submerge fill piping or bottom fill piping and painted white

Table D-10.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0930	CENTURION BROWNSVILLE	Fixed Roof Storage Tanks	10/19/2021	Volatile Organic Compounds (VOC)	1260000	GAL/HR/TANK	0			Tanks must be painted white or unpainted aluminum, utilize submerged fill, and designed to be drain-dry.
TX-0930	CENTURION BROWNSVILLE	Fixed Roof Storage Tanks MSS	10/19/2021	Volatile Organic Compounds (VOC)	0		0			tanks containing VOC liquids alone or in combination with other liquids shall be depressurized and degassed to control until the vapor space concentration has been verified to be less than or equal to 4,000 ppmv. Tanks may be opened without restriction and ventilated without control when there is either no liquid and/or sludge remaining in the tank, or the vapor pressure of the liquid and/or sludge remaining in the tank has a vapor pressure less than 0.02 psia.
TX-0936	BILL GREEHEY REFINERY EAST PLANT	FIXED ROOF STORAGE TANKS	03/29/2022	Volatile Organic Compounds (VOC)	0		0			Vertical fixed roof tanks storing low vapor pressure products (vp < 0.5 psia) with submerged fill, painted white.
*TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FIXED ROOF STORAGE TANKS	07/20/2023	Volatile Organic Compounds (VOC)	0		0			Vertical fixed roof tanks storing low vapor pressure products (vp < 0.5 psia) with submerged fill, painted white.
*TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FIXED ROOF TANK MSS	07/20/2023	Volatile Organic Compounds (VOC)	0		0			Fixed roof tank draining: Send liquid to a covered vessel. If there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia. Control device (portable combustor) has a minimum DRE of 99%. Maintain fixed roof tanks only when warranted by inspection.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	STORAGE TANKS	03/13/2023	Volatile Organic Compounds (VOC)	0		0			Bottom fill, exterior surfaces are painted white, unpainted stainless steel, or unpainted aluminum.
*TX-0967	QUAIL RUN CARBON CAPTURE PLANT	Fixed Roof Storage Tanks	02/05/2024	Volatile Organic Compounds (VOC)	0		0			Submerged fill and uninsulated exterior surfaces exposed to the sun are painted white. Send liquid to a covered vessel when draining the tank.
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	FT02 â€” Diesel Fuel Tank Storage	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Good Operating Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	T01, T02, & T03 Diesel Storage Tank	04/24/2018	Volatile Organic Compounds (VOC)	0		0			Submerged Fill Pipe
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Day Tank (T01)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Generator Tank (T02)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			

Table D-10.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Fire Pump Tank (T03)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Tank (T100)	09/27/2019	Volatile Organic Compounds (VOC)	0		932.3	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe, may store only asphalt
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Tank (T118)	09/27/2019	Volatile Organic Compounds (VOC)	0		1886.4	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe and tank may only store asphalt
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Blending (T119)	09/27/2019	Volatile Organic Compounds (VOC)	0		448.1	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe and tank may store only asphalt
WI-0315	SUPERIOR REFINING COMPANY LLC	Storage Tanks (T88, T90, T91)	10/09/2020	Volatile Organic Compounds (VOC)	0		718.3	LB/MO	AVG., ANY 12-CONSECUTIVE MONTHS	Use of submerged fill pipe, may store only asphalt

Table D-10.2 Summary of CO_2e BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0888	ORANGE POLYETHYLENE PLANT	FIXED ROOF STORAGE TANKS	04/23/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			submerge fill piping or bottom fill piping and painted white

Table D-11.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, filterable (FPM)	0		15.2	LB/HR		Water Sprays, sweeping,
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, filterable (FPM)	0		2.8	TPY		Development and Implementation of Fugitive Dust Control Plan
IN-0324	MIDWEST FERTILIZER COMPANY LLC	Fugitive dust from paved roads and parking lots	05/06/2022	Particulate matter, filterable (FPM2.5)	0		0			
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, filterable (FPM)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, filterable (FPM)	0		0			Sweeping & Watering
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	haul roads	05/12/2016	Particulate matter, filterable (FPM)	0		0			vacuum sweep, wash, etc
OH-0376	IRONUNITS LLC - TOLEDO HBI	Paved roads (F001)	02/09/2018	Particulate matter, filterable (FPM10)	0		0.63	T/YR		water flushing and sweeping
OH-0376	IRONUNITS LLC - TOLEDO HBI	Paved roads (F001)	02/09/2018	Particulate matter, filterable (FPM2.5)	0		0.15	T/YR		water flushing and sweeping
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Plant Roadways & Parking Areas (F005)	09/27/2019	Particulate matter, filterable (FPM10)	686399	MI/YR	3.55	T/YR	PER ROLLING, 12-MONTH PERIOD.	Paved: sweeping, vacuuming, washing with water, and posted speed limits to comply with the applicable requirements. Unpaved: use of dust suppressant as necessary to comply with the applicable requirements.
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Plant Roadways & Parking Areas (F005)	09/27/2019	Particulate matter, filterable (FPM2.5)	686399	MI/YR	0.75	T/YR	PER ROLLING, 12-MONTH PERIOD.	Paved: sweeping, vacuuming, washing with water, and posted speed limits to comply with the applicable requirements. Unpaved: use of dust suppressant as necessary to comply with the applicable requirements.

Table D-11.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0387	INTEL OHIO SITE	Facility paved roadways and parking areas	09/20/2022	Particulate matter, filterable (FPM10)	0		0.16	T/YR	PER ROLLING 12 MONTH PERIOD	Pave all roadways and parking areas and implement best management practices, including limiting vehicle speeds and water spraying or sweeping as needed based on daily inspections.
OH-0387	INTEL OHIO SITE	Facility paved roadways and parking areas	09/20/2022	Particulate matter, filterable (FPM2.5)	0		0.04	T/YR	PER ROLLING 12 MONTH PERIOD	Pave all roadways and parking areas and implement best management practices, including limiting vehicle speeds and water spraying or sweeping as needed based on daily inspections.
*OH-0391	VALENCIA PROJECT LLC	Paved Roads (F001)	10/27/2023	Particulate matter, filterable (FPM10)	0		0.92	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
*OH-0391	VALENCIA PROJECT LLC	Paved Roads (F001)	10/27/2023	Particulate matter, filterable (FPM2.5)	0		0.23	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
*OH-0392	NUCOR STEEL MARION, INC.	Vehicular Traffic (F001)	02/27/2024	Particulate matter, filterable (FPM10)	0		4.4	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
*OH-0392	NUCOR STEEL MARION, INC.	Vehicular Traffic (F001)	02/27/2024	Particulate matter, filterable (FPM2.5)	0		0.63	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM)	0		0.13	LB/VMT		Good housekeeping practices.
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM10)	0		0.03	LB/VMT		Good housekeeping practices.
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM2.5)	0		0.01	LB/VMT		Good housekeeping practices.

Table D-11.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, total (TPM10)	0		3.9	LB/HR		Water Sprays, sweeping,
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, total (TPM2.5)	0		0.5	LB/HR		Water Sprays, sweeping,
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, total (TPM10)	0		0.6	TPY		Development and Implementation of Fugitive Dust Control Plan
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, total (TPM2.5)	0		0.2	TPY		Development and Implementation of Fugitive Dust Control Plan
*IA-0117	SHELL ROCK SOY PROCESSING	Paved Road Fugitives	03/17/2021	Particulate matter, total (TPM)	0		2.97	TONS PER YEAR	PM	sweeping
IL-0129	CPV THREE RIVERS ENERGY CENTER	Roadways	07/30/2018	Particulate matter, total (TPM)	0		10	% OPACITY		Paving is required for roads used by trucks transporting bulk materials.
IL-0130	JACKSON ENERGY CENTER	Roadways	12/31/2018	Particulate matter, total (TPM)	0		10	PERCENT OPACITY		
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM10)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM2.5)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0133	LINCOLN LAND ENERGY CENTER	Roadways	07/29/2022	Particulate matter, total (TPM)	0		10	PERCENT OPACITY	FROM FUGITIVE EMISSIONS	

Table D-11.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IL-0134	CRONUS CHEMICALS	Roadways	12/21/2023	Particulate matter, total (TPM10)	0		10	PERCENT	OPACITY FROM ROADWAYS	Paving of all roadways and Fugitive Dust Control Plan, including mitigative measures (sweeping, water sprays, prompt cleanups)
*IL-0134	CRONUS CHEMICALS	Roadways	12/21/2023	Particulate matter, total (TPM2.5)	0		10	PERCENT	OPACITY FROM ROADWAYS	Paving of all roadways and Fugitive Dust Control Plan, including mitigative measures (sweeping, water sprays, prompt cleanups)
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM10)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM2.5)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0324	MIDWEST FERTILIZER COMPANY LLC	Fugitive dust from paved roads and parking lots	05/06/2022	Particulate matter, total (TPM10)	0		0			
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, total (TPM10)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, total (TPM2.5)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, total (TPM10)	0		0			Sweeping & Watering
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, total (TPM2.5)	0		0			Sweeping & Watering

Table D-11.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	Fugitive Dust (Paved Roads)	05/04/2021	Particulate matter, total (TPM10)	0		0.08	LB/HR		Paving plant road as much as practicable.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	Fugitive Dust (Paved Roads)	05/04/2021	Particulate matter, total (TPM)	0		0.08	LB/HR		Paving plant road as much as practicable.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Paved Roads (FUG0004)	04/25/2019	Particulate matter, total (TPM10)	0		0			Proper maintenance
LA-0382	BIG LAKE FUELS METHANOL PLANT	Paved Roads (FUG0004)	04/25/2019	Particulate matter, total (TPM2.5)	0		0			Proper maintenance
OH-0368	PALLAS NITROGEN LLC	Paved Roadways (F001)	04/19/2017	Particulate matter, total (TPM10)	70000	MI/YR	2.6	T/YR		i.Paving of all plant roads that will be used for raw material and product transport; ii.Covering, at all times, of open-bodied vehicles when transporting materials likely to become airborne; and iii.Compliance with the opacity limits. Specifically, additional mitigation measures potentially including road sweeping or wet suppression will be implemented on an as-needed basis determined through visual observation of emissions associated with truck movements on the plant site.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Facility Roadways (F001)	12/21/2018	Particulate matter, total (TPM10)	182865	MI/YR	0.38	T/YR	PER ROLLING 12 MONTH PERIOD	i.Pave all in-plant haul roads and parking areas; ii.Implement best management practices including posting and limiting vehicle speeds to 20 miles per hour and water spraying or sweeping as needed based on the daily inspections conducted
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Facility Roadways (F001)	12/21/2018	Particulate matter, total (TPM2.5)	182865	MI/YR	0.09	T/YR	PER ROLLING 12 MONTH PERIOD	i.Pave all in-plant haul roads and parking areas; ii.Implement best management practices including posting and limiting vehicle speeds to 20 miles per hour and water spraying or sweeping as needed based on the daily inspections conducted

Table D-11.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0380	AMG VANADIUM LLC	Paved Roadways (F001)	08/07/2019	Particulate matter, total (TPM10)	31689	MI/YR	0.06	T/YR	PER ROLLING 12-MONTH PERIOD.	Pave all in-plant haul roads and parking areas. Implement best management practices including posting and limiting vehicle speeds to 15 miles per hour in production areas. Utilize a vacuum sweeper as needed based on the daily inspections
OH-0380	AMG VANADIUM LLC	Paved Roadways (F001)	08/07/2019	Particulate matter, total (TPM2.5)	31689	MI/YR	0.01	T/YR	PER ROLLING 12-MONTH PERIOD.	Pave all in-plant haul roads and parking areas. Implement best management practices including posting and limiting vehicle speeds to 15 miles per hour in production areas. Utilize a vacuum sweeper as needed based on the daily inspections
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD	Roads	10/31/2023	Particulate matter, total (TPM10)	0		0			Paving and maintaining all roads
*SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD	Roads	10/31/2023	Particulate matter, total (TPM2.5)	0		0			Paving and maintaining all roads
WI-0310	NEMADJI TRAIL ENERGY CENTER	Haul Roads (F01)	07/08/2021	Particulate matter, total (TPM)	0		520	TRUCK TRIPS/YR	ANY CONSECUTIVE 12-MO PERIOD	All roads and parking lots within the property boundary must be paved, 5 mph speed limits posted for all vehicles and develop, maintain, and implement a fugitive dust control plan.
WI-0310	NEMADJI TRAIL ENERGY CENTER	Haul Roads (F01)	07/08/2021	Particulate matter, total (TPM10)	0		520	TRUCK TRIPS/YR	ANY CONSECUTIVE 12-MO PERIOD	All roads and parking lots within the property boundary must be paved, 5 mph speed limits posted for all vehicles; and develop, maintain, and implement a fugitive dust control plan.

Table D-12.1 Summary of SF_6 BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0354	LAUDERDALE PLANT	Circuit Breakers	08/25/2015	Sulfur Hexafluoride	0		0.5	% PER YEAR	MUST HAVE CERTIFIED LEAK RATE LESS THAN	Limitation on leaks
FL-0355	FORT MYERS PLANT	Circuit breakers	09/10/2015	Sulfur Hexafluoride	0		0.5	PERCENT	LEAK RATE PER YEAR	Limitation on leak of SF6 from circuit breakers
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Circuit breakers	03/09/2016	Sulfur Hexafluoride	0		0			Leak prevention. Must have manufacturer-guaranteed leak rate no more than 0.5% per year. Must be equipped with leakage detection systems and alarms.
IL-0129	CPV THREE RIVERS ENERGY CENTER	Circuit Breakers	07/30/2018	Sulfur Hexafluoride	0		0.5	% LEAK RATE	CALENDAR YEAR AVERAGE	
IL-0130	JACKSON ENERGY CENTER	Circuit Breakers	12/31/2018	Sulfur Hexafluoride	0		0.5	PERCENT LEAK RATE	CALENDAR YEAR AVERAGE	
IL-0133	LINCOLN LAND ENERGY CENTER	Circuit Breakers	07/29/2022	Sulfur Hexafluoride	0		0.5	PERCENT LEAK RATE	12-MONTH ROLLING AVERAGE	
MD-0045	MATTAWOMAN ENERGY CENTER	CIRCUIT BREAKERS	11/13/2015	Sulfur Hexafluoride	0		0			
PA-0310	CPV FAIRVIEW ENERGY CENTER	Circuit breakers	09/02/2016	Sulfur Hexafluoride	0		1500	PPM		State-of-the-art sealed enclosed-pressure circuit breakers with leak detection
FL-0363	DANIA BEACH ENERGY CENTER	Circuit breakers (two)	12/04/2017	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year
IN-0294	ST. JOSEPH ENERGY CENTER, LLC	Circuit Breakers SF6	08/08/2018	Sulfur Hexafluoride	0		0			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Circuit breakers with SF6	12/23/2015	Sulfur Hexafluoride	0		6	LB/12MO	ANY 12 CONSECUTIVE MONTH PERIOD	low pressure alarms and low pressure lockout system
WI-0299	WPL- RIVERSIDE ENERGY CENTER	Sulfur Hexafluoride Containing Circuit Breakers and Transformers (F90)	08/20/2020	Sulfur Hexafluoride	0		0.5	% LEAK RATE, BY WGHT	ANNUALLY	

Table D-12.1 Summary of SF_6 BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Two Circuit Breakers	07/27/2018	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Two Circuit Breakers	06/07/2021	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year

Table D-12.2 Summary of CO_2e BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Circuit Breakers	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	0		85	T/YR		Enclosed pressure design with a low pressure detection system with an alarm to limit SF6 leak rate to 0.5 % per year.
MD-0045	MATTAWOMAN ENERGY CENTER	CIRCUIT BREAKERS	11/13/2015	Carbon Dioxide Equivalent (CO_2e)	0		0			GHG BACT FOR THE CIRCUIT BREAKERS SHALL BE INSTALLATION OF STATE-OF-THE-ART CIRCUIT BREAKERS THAT ARE DESIGNED TO MEET ANSI C37.013 OR EQUIVALENT TO DETECT AND MINIMIZE SF6 LEAKS
VA-0332	CHICKAHOMINY POWER LLC	Circuit Breakers	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	0.5	%	0			Enclosed-pressure design with low-pressure detection system (with alarm).
VA-0328	C4GT, LLC	Circuit Breakers - 6	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	0.5	%	0			Enclosed-pressure design with low-pressure detection system (with alarm).
VA-0325	GREENSVILLE POWER STATION	CIRCUIT BREAKERS (11)	06/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		1032	T/YR		Enclosed pressure type breaker and leak detection
VA-0325	GREENSVILLE POWER STATION	CIRCUIT BREAKERS (3)	06/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		19	T/YR		Enclosed pressure type breaker and leak detector
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Circuit breakers with SF6	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	0		79.8	TONS	ANY 12 CONSECUTIVE MONTH PERIOD	
TX-0753	GUADALUPE GENERATING STATION	Fugitive SF6 Circuit Breaker Emissions	12/02/2014	Carbon Dioxide Equivalent (CO_2e)	0		0			
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Insulated circuit breaker	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	0		6.9	TONS PER YEAR		Installation of modern, totally enclosed SF6 circuit breakers with density (leak detection) alarms and a guaranteed loss rate of < 0.5 % by weight per year.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Low-Side Generator Enclosed Pressure SF6 Circuit Breakers (F03)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	0		0.5	% BY WEIGHT/YEAR		
TX-0824	JACKSON COUNTY GENERATING FACILITY	Sulfur hexafluoride (SF6) insulated Electrical Equipment	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	0		34.4	T/YR		The use of circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout is BACT

Table D-13.1 Summary of CO BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*TX-0964	NEDERLAND FACILITY	EQUIPMENT FUGITIVES	10/05/2023	Carbon Monoxide	0		0			Good management practice and personal portable CO monitors for leaking detection

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	, Petroleum Refining Equipment Leaks/Fugitive Emissions	04/10/2015	Volatile Organic Compounds (VOC)	100000	Bbl/day	36.6	TPY		Quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 parts per million volume (ppmv) for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	AMMONIA FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28AVO LDAR program
LA-0362	LAKE CHARLES REFINERY, AREA D	Area D Process D Fugitives	07/18/2019	Volatile Organic Compounds (VOC)	0		24.44	LB/H		Compliance with the most stringent applicable Leak Detection and Repair (LDAR) program, which is Louisiana MACT Determination for Refineries with Consent
IN-0317	RIVERVIEW ENERGY CORPORATION	Block 4000 fugitive emissions	06/11/2019	Volatile Organic Compounds (VOC)	0		25.04	TONS	12 CONSECUTIVE MONTHS	Leak detection and repair (LDAR) program
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	DIESEL FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28PI LDAR
TX-0812	CRUDE OIL PROCESSING FACILITY	Equipment Leaks	10/31/2016	Volatile Organic Compounds (VOC)	0		8.72	T/YR		Quarterly instrumental monitoring of accessible pumps, compressors and valves in vapor or light liquid service, with leak definitions of 500 ppmv (valves) and 2,000 ppmv (pump and compressor seals). Upon detection of a leak, a first attempt to
TX-0847	VALERO PORT ARTHUR REFINERY	Equipment Leaks/Fugitive Emissions	09/16/2018	Volatile Organic Compounds (VOC)	0		0			28 VHP
*WI-0273	SUPERIOR REFINING COMPANY LLC	F1: Fugitive Components	07/15/2022	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Fugitive Components	06/19/2015	Volatile Organic Compounds (VOC)	0		500	PPMV	VALVES	Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves with a leak definition of 500 ppmv. Quarterly monitoring of pump and compressor seals with a leak
TX-0852	CORPUS CHRISTI WATERFRONT TERMINAL	Fugitive Components	01/02/2019	Volatile Organic Compounds (VOC)	0		0			28LAER
TX-0914	BORGER REFINERY	FUGITIVE COMPONENTS	01/21/2021	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0916	CEDAR BAYOU	FUGITIVE COMPONENTS	02/01/2021	Volatile Organic Compounds (VOC)	0		0			28 VHP

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0930	CENTURION BROWNSVILLE	Fugitive Components	10/19/2021	Volatile Organic Compounds (VOC)	0		0			Leak detection and repair (LDAR) monitoring and directed maintenance in accordance with the 28VHP program. Quarterly instrumental monitoring using a Method 21 gas analyzer.
WI-0311	SUPERIOR REFINING COMPANY LLC	Fugitive Components (F100)	09/27/2019	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)
WI-0315	SUPERIOR REFINING COMPANY LLC	Fugitive components (F100)	10/09/2020	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)
LA-0316	CAMERON LNG FACILITY	fugitive emissions	02/17/2017	Volatile Organic Compounds (VOC)	0		0			Complying with LAC 33:III.2111
LA-0356	GARYVILLE REFINERY	Fugitive Emissions (Unit 305, Unit 333, Refinery, GRL)	09/27/2019	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa
LA-0331	CALCASIEU PASS LNG PROJECT	Fugitive Equipment Leaks	09/21/2018	Volatile Organic Compounds (VOC)	0		5	T/YR	ANNUAL TOTAL	Proper piping design and compliance with LAC 33:III.2111.
*TX-0962	POINT COMFORT PLANT	Fugitive Piping Leaks	09/22/2023	Volatile Organic Compounds (VOC)	0		0			A modified version of the 28VHP LDAR program using a 500 ppm leak definition is used. 28CNTA. 28PI specifically for mineral oil service.
TX-0760	CORPUS CHRISTI TERMINAL	Fugitives	08/06/2015	Volatile Organic Compounds (VOC)	0		500	PPMV		Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
TX-0840	CORPUS CHRISTI TERMINAL	FUGITIVES	10/31/2018	Volatile Organic Compounds (VOC)	0		0			Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
TX-0850	CORPUS CHRISTI TERMINAL	FUGITIVES	07/15/2018	Volatile Organic Compounds (VOC)	0		0			28 MID
TX-0851	RIO BRAVO PIPELINE FACILITY	FUGITIVES	12/17/2018	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0855	BUCKEYE SOUTH TEXAS GATEWAY TERMINAL	Fugitives	03/13/2019	Volatile Organic Compounds (VOC)	0		0			28 VHP, 28PI LDAR
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FUGITIVES	08/29/2019	Volatile Organic Compounds (VOC)	0		0			28VHP LDAR

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0871	PORT ARTHUR REFINERY	Fugitives	01/31/2020	Volatile Organic Compounds (VOC)	0		0			28VHP leak detection and repair (LDAR)
TX-0873	PORT ARTHUR REFINERY	FUGITIVES	02/04/2020	Volatile Organic Compounds (VOC)	0		0			28 MID, 28 AVO and OGI fugitive programs. Authorized for infrared camera (28MID+).
TX-0874	PORT ARTHUR REFINERY	FUGITIVES	02/04/2020	Volatile Organic Compounds (VOC)	0		0			28MID LDAR and 28CNTQ.
TX-0878	LNG EXPORT TERMINAL	FUGITIVES	09/15/2022	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0887	MIDLAND PLAINS MARKETING TERMINAL	Fugitives	04/07/2020	Volatile Organic Compounds (VOC)	0		0			The site-wide fugitive emissions are less than 10 tpy uncontrolled VOC emissions. LADR program and emission reduction credit is not applied.
TX-0892	NEDERLAND TERMINAL	fugitives	07/13/2020	Volatile Organic Compounds (VOC)	0		0			28-VHP LDAR fugitive
TX-0909	POLYETHYLENE UNIT 1792	Fugitives	12/08/2020	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0910	POLYETHYLENE UNIT 1796	FUGITIVES	12/11/2020	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0929	FORMOSA POINT COMFORT PLANT	FUGITIVES	10/15/2021	Volatile Organic Compounds (VOC)	0		0			modified 28VHP LDAR program in VOC service. A more stringent 500ppmv leak definition of 28MID is used. Annual 28CNTA monitoring is voluntarily used.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Fugitives (FUG0001)	09/03/2020	Volatile Organic Compounds (VOC)	0		0			Proper piping design and LDAR
TX-0872	CONDENSATE SPLITTER FACILITY	Fugitives (Routine)	10/31/2019	Volatile Organic Compounds (VOC)	0		15.63	LB/H		28VHP. Leak-less connectors.
LA-0355	GARYVILLE REFINERY	Fugitives from Crude Unit, Coker Unit and FCCU	09/06/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa
*TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FUGITVES	07/20/2023	Volatile Organic Compounds (VOC)	0		0			28VHP & 28AVO

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0759	PORT ARTHUR REFINERY	Hydrocracking and Hydro-treating Fugitive Components	07/31/2015	Volatile Organic Compounds (VOC)	105	K BBL/DAY	500	PPM	VALVES, PUMPS, SEALS	Enhanced Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves, pumps, and compressor seals with a leak definition of 500 ppmv. Enhancements to the LDAR program include: 1) Monitoring to be done with data loggers capable of assigning time stamps to individual monitoring events; 2) Repair of leaking components found during weekly physical inspections within 15 days; 3) First attempt of repair of any valve found with a VOC reading greater than 100 ppmv; 4) Conduct of annual training for all of all LDAR technicians in the application of Method 21 consistent with the requirements of the permit; 5) Performance of a third party audit by no later than December 31, 2015 and then at least once every two years thereafter to verify whether EPA Method 21 is being properly applied; 6) and Initiation of an optical gas imaging (OGI) enhanced monitoring program for equipment leaks at those process units subject to EPA Method 21. In addition to the enhanced program, Motiva has agreed to perform quarterly instrument monitoring on fugitive components in heavy liquid service as well as quarterly instrument monitoring on all connectors with a leak definition of 500
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	LNG Export Facility - Natural Gas Fugitive Emissions	02/17/2016	Volatile Organic Compounds (VOC)	0		21.65	T/YR		Work practice - leak detection and repair program (28 VHP LDAR program)
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	NATURAL GAS FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28AVO LDAR program

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0765	SUNOCO MARINE VESSEL LOADING OPERATIONS	Petroleum Refining Equipment Leaks/Fugitive Emissions	09/18/2015	Volatile Organic Compounds (VOC)	100	MMbbl/yr	10.13	TPY		Quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 ppmv for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak.
TX-0797	CORPUS CHRISTI TERMINAL	Petroleum Refining Equipment Leaks/Fugitive Emissions	05/04/2016	Volatile Organic Compounds (VOC)	0		500	PPM		Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	PG02, PG03, and PG11 Pigging Equipment/Operations	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with Leak Detection and Repair (LDAR) Program
WI-0307	ENBRIDGE SUPERIOR TERMINAL	Piping Component Equipment Leak Fugitive (F01A)	09/22/2021	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Use certified low-leaking valves or fit certified low-leaking valve packing technology on pressure relief piping and leak detection and repair (LDAR) program.
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	Process NameF01 Piping Component/Pumping Fugitive	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with Leak Detection and Repair (LDAR) Program
TX-0872	CONDENSATE SPLITTER FACILITY	Product Sampling Vacuum Truck (MSS)	10/31/2019	Volatile Organic Compounds (VOC)	0		0			Contained in a sealable container. Best Management Practices including minimizing MSS activity and recordkeeping. Maximum sample size 32 oz.
LA-0385	GARYVILLE REFINERY	Refinery Fugitives	02/11/2021	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa (for components servicing streams with 10% or more VOC)
TX-0936	BILL GREEHEY REFINERY EAST PLANT	REFINERY FUGITIVES	03/29/2022	Volatile Organic Compounds (VOC)	0	MBF/YR	0			28VHP, 28AVO
WI-0307	ENBRIDGE SUPERIOR TERMINAL	Temporary Loading (TL01)	09/22/2021	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		See notes.
LA-0284	ALLIANCE REFINERY	Unit Fugitives for Loading Docks (406-FF, FUG 11)	09/02/2015	Volatile Organic Compounds (VOC)	0		0			LDAR: 40 CFR 63 Subpart H

Table D-13.2 Summary of VOC BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0283	ALLIANCE REFINERY	UNIT FUGITIVES FOR LOW SULFUR GASOLINE UNIT (294-FF, FUG 0004)	08/14/2015	Volatile Organic Compounds (VOC)	0		15.43	LB/HR	HOURLY AVERAGE	LDAR: Louisiana MACT Determination for Refinery Equipment Leaks (Fugitive Emission Sources) dated July 26, 1994
LA-0282	ALLIANCE REFINERY	Unit Fugitives for the Low Sulfur Gasoline Unit (294-FF, FUG 0004)	04/02/2015	Volatile Organic Compounds (VOC)	0		15.43	LB/HR	HOURLY AVERAGE	Louisiana MACT Determination for Refinery Equipment Leaks (Fugitive Emission Sources) dated July 26, 1994

Table D-13.3 Summary of Total PM10/PM2.5 BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*MN-0093	FLINT HILLS RESOURCES PINE BEND REFINERY	#4 Coker Petroleum Coke Handling / FUGI24FUGPM (FUGI133)	01/13/2017	Particulate matter, total (TPM10)	0		8	PERCENT MINIMUM		Enclosed conveyor & coke pit (walls on all four sides) Minimum coke moisture content
*MN-0093	FLINT HILLS RESOURCES PINE BEND REFINERY	#4 Coker Petroleum Coke Handling / FUGI24FUGPM (FUGI133)	01/13/2017	Particulate matter, total (TPM2.5)	0		8	PERCENT MINIMUM		Enclosed conveyor & coke pit (walls on all four sides) Minimum coke moisture content

Table D-13.4 Summary of CO_2e BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*TX-0964	NEDERLAND FACILITY	EQUIPMENT FUGITIVES	10/05/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			Good management practice and personal portable CO □ monitors for leaking detection
TX-0847	VALERO PORT ARTHUR REFINERY	Equipment Leaks/Fugitive Emissions	09/16/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0914	BORGER REFINERY	FUGITIVE COMPONENTS	01/21/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			28VHP
LA-0316	CAMERON LNG FACILITY	fugitive emissions	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	0		0			Implement a leak detection and repair (LDAR) program to minimize the leak
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	Fugitive Emissions	09/11/2015	Carbon Dioxide Equivalent (CO_2e)	0		2569	TPY		Work practice leak detection and repair program
LA-0331	CALCASIEU PASS LNG PROJECT	Fugitive Equipment Leaks	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	0		3141	T/YR	ANNUAL TOTAL	Proper piping design.
TX-0801	PL PROPYLENE HOUSTON OLEFINS PLANT	Fugitives	06/24/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			LDAR 28LAER
TX-0851	RIO BRAVO PIPELINE FACILITY	FUGITIVES	12/17/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	FUGITIVES	09/09/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			28LAER & 28PI LDAR
TX-0878	LNG EXPORT TERMINAL	FUGITIVES	09/15/2022	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0881	EXXONMOBIL BEAUMONT REFINERY	FUGITIVES	01/10/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Compliance with Refinery MACT fugitives and Texas 28VHP LDAR program.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Fugitives (FUG0001)	09/03/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Proper piping design and LDAR

Table D-13.4 Summary of CO_2e BACT Determinations for Natural Gas Piping Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0759	PORT ARTHUR REFINERY	Hydrocracking and Hydro-treating Fugitive Components	07/31/2015	Carbon Dioxide Equivalent (CO_2e)	105	K BBL/DAY	500	PPMV		Enhanced Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves, pumps, and compressor seals with a leak definition of 500 ppmv. Enhancements to the LDAR program include: 1) Monitoring to be done with data loggers capable of assigning time stamps to individual monitoring events; 2) Repair of leaking components found during weekly physical inspections within 15 days; 3) First attempt of repair of any valve found with a VOC reading greater than 100 ppmv; 4) Conduct of annual training for all of all LDAR technicians in the application of Method 21 consistent with the requirements of the permit; 5) Performance of a third party audit by no later than December 31, 2015 and then at least once every two years thereafter to verify whether EPA Method 21 is being properly applied; 6) and Initiation of an optical gas imaging (OGI) enhanced monitoring program for equipment leaks at those process units subject to EPA Method 21. In addition to the enhanced program, Motiva has agreed to perform quarterly instrument monitoring on fugitive components in heavy liquid service as well as quarterly instrument monitoring on all connectors with a leak definition of 500
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	LNG Export Facility - Natural Gas Fugitive Emissions	02/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		1113	T/YR		Work practice - leak detection and repair program (TCEQ 28 VHP LDAR program)
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	NATURAL GAS FUGITIVES	03/13/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			28AVO LDAR program

APPENDIX E. BACT SUPPORTING DOCUMENTATION

Appendix E, Table E-2.1 – Cost Analysis Summary

EU Name	Reduction Option	Capital Costs	Total Annual Costs	Cost Effectiveness
Aux Boiler	NO_x - SCR	$2,911,068	$302,651	$27,230/ton
	NO_x - SNCR	$947,119	$114,134	$15,230/ton

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	78.32	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,060	Btu/scf
What is the estimated actual annual fuel consumption?	647,248,302	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW
Plant Elevation	834	Feet above sea level

*HHV value of 1060 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.036 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.004 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024	
CEPCI for 2024	800.3 Enter the CEPCI value for 2024 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5 Percent	
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0450 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0450	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Site-specific estimate used in Cooper Project engineering design basis
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,060	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site-specific estimate used in Cooper Project engineering design basis
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	7.5	Default bank prime rate	Bank prime rate is as of January 2025 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	78	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	647,248,302	scf/Year	
Actual Annual fuel consumption (Mactual) =		647,248,302	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	2.54	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	11.11	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	36,273	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	119.15	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	304.42	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	38	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	43	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	6.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	3	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to tl

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0897

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	40.27	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$2,911,068	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$38,726	in 2024 dollars
Indirect Annual Costs (IDAC) =	$263,926	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$302,651	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$14,555	in 2024 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,166	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$15,875	in 2024 dollars
Annual Catalyst Replacement Cost =		$7,129	in 2024 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$38,726	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,803	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$261,123	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$263,926	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$302,651	per year in 2024 dollars
NOx Removed =	11.1	tons/year
Cost Effectiveness =	$27,230	per ton of NOx removed in 2024 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? New Construction

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 78.32 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,060 Btu/scf

*HHV value of 1060 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 647,248,302 scf/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.036	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.015	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

Plant Elevation: 250 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2024			
CEPCI for 2024	800.3	Enter the CEPCI value for 2024	541.7	2016 CEPCI
Annual Interest Rate (i)	7.5	Percent		
Fuel ($Cost_{fuel}$)	3.35	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0450	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0450	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Site-specific estimate used in Cooper Project engineering design basis
Fuel Cost ($/MMBtu)	3.35	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	U.S. Energy Information Administration. Monthly Natural Gas Prices by State (Dollars per Thousand Cubic Feet). Year-to-Date 2024 Avg. from January-October 2024 https://www.eia.gov/dnav/ng/hist/n3035ky3m.htm
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,060	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site-specific estimate used in Cooper Project engineering design basis
Interest Rate	7.5	Default bank prime rate	Bank prime rate is as of January 2025 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	78.32	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	647,248,302	scf/Year	
Actual Annual fuel consumption (Mactual) =		647,248,302	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	1.000	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	60	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.71	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	7.49	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	#VALUE!		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	New Construction	0.84		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	2	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	4	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	0.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0981

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)$/NPHR =	0.2	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	2	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.02	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)$/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$134,862	in 2024 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2024 dollars
Balance of Plant Costs (BOP_{cost}) =	$593,691	in 2024 dollars
Total Capital Investment (TCI) =	$947,119	in 2024 dollars

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$134,862	in 2024 dollars

Air Pre-Heater Costs (APH_{cost})*
For Coal-Fired Utility Boilers:
$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$
For Coal-Fired Industrial Boilers:
$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2024 dollars

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	\$593,691 in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$20,795	in 2024 dollars
Indirect Annual Costs (IDAC) =	$93,339	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$114,134	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$14,207	in 2024 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$5,988	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$68	in 2024 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$68	in 2024 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$464	in 2024 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2024 dollars
Direct Annual Cost =		$20,795	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$426	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$92,912	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$93,339	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$114,134	per year in 2024 dollars
NOx Removed =	7.49	tons/year
Cost Effectiveness =	$15,230	per ton of NOx removed in 2024 dollars

APPENDIX F. SUGGESTED PERMIT

Permit Number: V-18-027

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 02: **Indirect Heat Exchanger (Unit 2)**

Description:	Pulverized Coal-Fired, Dry-Bottom, Wall-Fired Unit
Primary Fuel:	Pulverized Coal, Natural Gas, or Co-fired
Secondary Fuel:	Natural Gas with Coal~~Wood Waste (up to 3% by weight in blend)~~
Startup Fuel:	Number Two Fuel Oil and/or Natural Gas
Maximum Continuous Rating:	2,433 MMBtu/hr
~~(coal co-firing with/or 100% natural gas)~~	
Control Devices:	Low NO_x burners; Dry Flue Gas Desulfurization (DFGD); Selective Catalytic Reduction (SCR); Pulse Jet Fabric Filter (PJFF) (DFGD and PJFF shared with Unit 1); and FuelSolv Treatment
Construction Commenced:	1969; Low NO_x burners installed 1994; FGD, SCR, and PJFF installed in 2012; FGD and PJFF in operation since June 30, 2012. Duct reroute to DFGD and PJFF completed April 2016; PM CEMS installed on or before December 31, 2012 as required by the Notice of Non-Material Change to Consent Decree filed October 7, 2011 and the Consent Decree filed September 24, 2007, Civil Action No. 04-34-KSF

APPLICABLE REGULATIONS:

40 CFR 52, Subpart S, *Kentucky* (BART SIP)
40 CFR Part 64, *Compliance Assurance Monitoring* (For PM)
40 CFR Part 75, *Continuous Emissions Monitoring*
401 KAR 51:017, *Prevention of Significant Deterioration of Air Quality*
401 KAR 51:240, *Cross-State Air Pollution Rule (CSAPR) NOx annual trading program* (See Section L)
401 KAR 51:250, *Cross-State Air Pollution Rule (CSAPR) NOx ozone season group 2 trading program* (See Section L)
401 KAR 51:260, *Cross-State Air Pollution Rule (CSAPR) SO2 group 1 trading program* (See Section L)
401 KAR 51:160, *NOx requirements for large utility and industrial boilers*
~~**401 KAR 51:210**, *CAIR NOx annual trading program* (See Section K)~~
~~**401 KAR 51:220**, *CAIR NOx ozone season trading program* (See Section K)~~
~~**401 KAR 51:230**, *CAIR SO2 trading program* (See Section K)~~
401 KAR 52:060, *Acid rain permits* (See Section J)
401 KAR 61:015, *Existing indirect heat exchangers*
401 KAR 63:002, Section 2(4)(yyyyy), 40 C.F.R. 63.9980 to 63.10042, Tables 1 to 9, and Appendices A to B (**Subpart UUUUU**), *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*

NON-APPLICABLE REGULATIONS:

401 KAR 63:020, *Potentially Hazardous Matter or Toxic Substances*

APPLICABLE CONSENT DECREE:

Consent Decree entered September 24, 2007, Civil Action No. 04-34-KSF

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f. During a startup period or a shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 61:015, Section 9. The affected facility shall meet the work practice standards established in 40 CFR, Part 63, Table 3 to Subpart UUUUU, as established in 401 KAR 63:002, Section 2(4)(yyyy). [401 KAR 61:015, Section 9(1) and 401 KAR 61:015, Section 9(2)(b)]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **1. Operating Limitations (c) and (d)**.

g. When co-firing or natural gas firing, during startup and shutdown, the permittee shall minimize CO, VOC, PM, PM_{10}, $PM_{2.5}$ and H_2SO_4 emissions by complying with the applicable requirements in **1. Operating Limitations** (f). [401 KAR 51:017]

h. When co-firing or natural gas firing, the permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf to control emissions of H_2SO_4. [401 KAR 51:017]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **Section D.4.**

i. When co-firing or natural gas firing, the permittee shall utilize good combustion and operating practices to control emissions of CO, VOC, H_2SO_4, and CO_2. [401 KAR 51:017]

2. Emission Limitations:

a. Particulate matter (PM) emissions shall not exceed 0.23 lb/MMBtu [401 KAR 61:015, Section 4(1)(a)]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **3. Testing Requirements (a)**.

b. Emissions shall not exceed 40 percent opacity, except: [401 KAR 61:015, Section 4(1)(c)]

i. A maximum of 60 percent opacity shall be permissible for not more than one 6 minute period in any 60 consecutive minutes; and [401 KAR 61:015, Section 4(1)(c)1.]

ii. Emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions if the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 61:015, Section 4(1)(c) 3.]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements (a)** and **5. Specific Recordkeeping Requirements (b) and (c)**.

c. Sulfur dioxide (SO_2) emissions shall not exceed 3.3 lb/MMBtu based on 24-hour average [401 KAR 61:015, Section 5(1)]. Beginning on June 30, 2012, the permittee shall install and commence continuous operation of FGD technology on Unit 2 so as to achieve, and thereafter maintain, a 30-day Rolling Average SO_2 Removal Efficiency of at least 95 percent or a 30-Day Rolling Average SO2 Emission Rate of no greater than 0.100 lb/MMBtu. [Consent Decree entered September 24, 2007, paragraph 65]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Compliance Demonstration Method:
In determining Emission Rates for SO_2, the permittee shall use CEMS in accordance with the procedures specified in Cooper Station Monitoring Plan approved by the USEPA on December 20, 2013 and revised on June 17, 2016, unless otherwise approved by the Permitting Authority and/or USEPA. See also **4. Specific Monitoring Requirements (c)** and **Section D – Source Emission Limitations and Testing Requirements**.

d. Beginning on December 31, 2012, the permittee shall install and commence continuous operation of year-round SCR technology on Unit 2 so as to achieve, and thereafter maintain, a NO_X, 30-Day Rolling Average Emission Rate not greater than 0.080 lb/MMBtu. [Consent Decree entered September 24, 2007, paragraph 53]

Compliance Demonstration Method:
In determining Emission Rates for NO_X, the permittee shall use CEMS in accordance with the procedures specified in the Cooper Station Monitoring Plan approved by USEPA on December 20, 2013 and revised on June 17, 2016, unless otherwise approved by the Permitting Authority and/or USEPA. See also **4. Specific Monitoring Requirements (c)** and **Section D – Source Emission Limitations and Testing Requirements**.

e. Beginning April 15, 2016, filterable particulate matter emissions shall not exceed 0.030 lb/MMBtu. [Consent Decree entered September 24, 2007, paragraph 84]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **3. Testing Requirements (a)** and **Section D – Source Emission Limitations and Testing Requirements**.

f. Filterable PM emissions shall not exceed 0.030 lb/MMBtu. [Kentucky BART SIP]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **3. Testing Requirements (a)** and **Section D – Source Emission Limitations and Testing Requirements**.

g. Emissions of CO, VOC, NO_X, filterable PM, condensable PM, H_2SO_4, and CO_2 from EU2 (C2) Co-Fired Boiler shall not exceed the limits in the following table: [401 KAR 51:017]

Fuel	**Pollutant**	**Emission Limit**	**Averaging Period**
Co-Firing Natural Gas w/ Coal or 100% Natural Gas	CO	0.12 lb/MMBtu	3-hr*
	VOC	0.0055 lb/MMBtu	3-hr*
	NO_X	0.080 lb/MMBtu	30-day†
	FPM + CPM	0.030 lb/MMBtu	3-hour*
	H_2SO_4	0.005 lb/MMBtu	3-hour*
	CO_2	2,074 lb/MWh-g	12-mo rolling†

Permit Number: V-18-027

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

† For NO_X and CO_2 during firing natural gas alone or in combination with coal, includes periods of startup and shutdown.
* For CO, VOC, FPM + CPM, and H_2SO_4 during firing natural gas alone or in combination with coal, excludes periods of startup and shutdown.

Compliance Demonstration Method:
Compliance shall be demonstrated according to **3. Testing Requirements (h, i, j, and k), and 4. Specific Monitoring Requirements (j and k) and 5. Specific Recordkeeping Requirements (b.ix)**.

h. NO_X emissions from the combined stack for EU01 and EU02 shall not exceed 890 lb/hr on a 24-hr block average basis. [401 KAR 51:017 Section 9]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements (j) and 5. Specific Recordkeeping Requirements (b.ix)**.

~~g.~~ i. Emissions from each unit shall not exceed the limitations in the table below [40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of Part 63]. If the permittee elects to comply with these emission limitations using emissions averaging, emissions averaging shall be conducted according to 40 CFR 63.10009 and 40 CFR 63.10022.

Pollutant	Emission Limit	Compliance Demonstration
PM	0.030 lb/MMBtu **OR** 0.30 lb/MWh	Quarterly stack testing **OR** PM CEMS. [Table 5., Item 1; and Table 7. also 40 CFR 63.10005.]
Pollutant	**Emission Limit**	**Compliance Demonstration**
	OR	
Total non-Hg HAP Metals	0.000050 lb/MMBtu **OR** 0.50 lb/GWh	Quarterly stack testing [Table 5., Item 2; and Table 7. also 40 CFR 63.10005.]
	OR	
All of these: Antimony	0.80 lb/TBtu **OR** 0.0080 lb/GWh	
Arsenic	1.1 lb/TBtu **OR** 0.020 lb/GWh	
Beryllium	0.20 lb/TBtu **OR** 0.0020 lb/GWh	
Cadmium	0.30 lb/TBtu **OR** 0.0030 lb/GWh	

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

i. Notwithstanding the provisions of 40 CFR 63.10021(d)(1), and the requirements listed in 40 CFR 63.10006(g) and (h), and the requirements of 40 CFR 63.10006(f)(3), the permittee shall complete performance tests for the EGU as follows: [40 CFR 63.10006(f)(1)].

1. At least 45 calendar days, measured from the test's end date, shall separate performance tests conducted every quarter [40 CFR 63.10006(f)(1)(i)];

2. For annual testing: [40 CFR 63.10006(f)(1)(ii)]

A. At least 320 calendar days, measured from the test's end date, shall separate performance tests [40 CFR 63.10006(f)(1)(ii)(A)];

B. At least 320 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests [40 CFR 63.10006(f)(1)(ii)(B)];

C. At least 230 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and [40 CFR 63.10006(f)(1)(ii)(C)]

3. At least 1,050 calendar days, measured from the test's end date, shall separate performance tests conducted every 3 years. [40 CFR 63.10006(f)(1)(iii)]

ii. For units demonstrating compliance through quarterly emission testing, the permittee shall conduct a performance test in the 4th quarter of a calendar year if the EGU has skipped performance tests in the first 3 quarters of the calendar year. [40 CFR 63.10006(f)(2)]

iii. If the EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, the permittee shall complete an additional performance test in that period as follows: [40 CFR 63.10006(f)(3)]

1. At least 15 calendar days shall separate two performance tests conducted in the same quarter. [40 CFR 63.10006(f)(3)(i)]

2. At least 107 calendar days shall separate two performance tests conducted in the same calendar year. [40 CFR 63.10006(f)(3)(ii)]

3. At least 350 calendar days shall separate two performance tests conducted in the same 3 year period. [40 CFR 63.10006(f)(3)(iii)]

g. Performance tests conducted for 40 CFR 63, Subpart UUUUU shall be conducted according to 40 CFR 63.10007 and Table 5 to 40 CFR 63, Subpart UUUUU. [40 CFR 63.10005(b) and 63.10006]

h. The permittee shall conduct an initial performance test to demonstrate compliance with the applicable CO emission limit under 401 KAR 51:017 using EPA Method 10 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

i. The permittee shall conduct an initial performance test to demonstrate compliance with the applicable VOC emission limit under 401 KAR 51:017 using EPA Method 18, 25, or 25A or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

j. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable combined filterable and condensable PM emission limit under 401 KAR 51:017 using EPA Method 5 (filterable), or MATS-modified EPA Method 5 (filterable), and EPA Method 202 (condensable) or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

k. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable H_2SO_4 emission limit under 401 KAR 51:017 using EPA Method 8, CTM-013 and CTM-013A, or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

4. **Specific Monitoring Requirements**:

a. The permittee shall install, calibrate, operate, and maintain a continuous opacity monitoring (COM) system for accurate opacity measurement. Excluding exempted time periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate: [401 KAR 61:005, Section 3; 40 CFR 60, Appendix B, Performance Specification 1; and 401 KAR 52:020, Section 10]

   i. Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs; or

   ii. Within 30 minutes after the COM indicates exceedance of the opacity standard, determine opacity using U.S. EPA Reference Method 9:

      1. If emissions are visible, inspect the COM and/or the control equipment and make any necessary repairs.

      2. If a U.S. EPA Reference Method 9 cannot be performed, the reason for not performing the reading shall be documented.

b. To meet the monitoring requirement for PM, the permittee shall use a continuous emission monitoring system (CEMS) as an indicator of particulate matter emission as directed in Table 2. [40 CFR 64.4(a)(1)]

TABLE 2 - MONITORING APPROACH

CAM Monitoring Approach		Indicator #1
I.	**Indicator**	**PM Emission Rate**
A.	Measurement Approach	Continuous measurement of PM emission rate from the common baghouse outlet duct.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

II.	**Indicator Range**	An excursion is defined as a PM CEMS response that exceeds 0.027 lb/MMBtu for any ~~six hour~~six-hour block average operating period excluding startup, shutdown, or malfunction. If five percent or greater of the CEM data recorded in a calendar quarter show excursions above the pressure drop indicator level, the permittee triggers the threshold for a QIP.
III.	**Performance Criteria**	
A.	Data Representativeness	The one-minute averages recorded by the PM CEMS are reduced to one-hour averages and one-hour lb/MMBtu emission rates are calculated by the DAHS
B.	Verification of Operational Status	N/A
C.	QA/QC Practices and Criteria	Daily zero and span checks will be completed and documented. The instrument is recalibrated if the zero or span value exceeds ±4% of the reference value. Absolute Correlation Audits (ACA) and Relative Correlation Audits (RCA) are completed according to the procedures of 40 CFR 60, Appendix F, Procedure 2.
D.	Monitoring Frequency	Continuous measurement of PM emission rate.
IV.	**Data Collection Procedures**	One-hour averages and one-hour lb/MMBtu PM emission rates shall be kept in a form readily available for inspection.
V.	**Averaging Period**	PM emission rates shall be reported as one-hour averages and one-hour lb/MMBtu
VI.	**Recordkeeping**	PM emission rates shall be maintained for a period of 5 years.
VII	**Reporting**	The number, the duration, the cause of, and corrective action taken as a result of excursion.

If five percent or greater of the CEM data (six-hour average of PM values) recorded in a calendar quarter show excursions above the PM indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate matter standard while operating at representative conditions. The permittee shall submit a compliance test protocol as pursuant to 401 KAR 50:045, Performance Tests, before conducting the test. The Division may waive this testing requirement upon a determination that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

c. The permittee shall install, calibrate, maintain and operate CEMS for measuring NO_x, SO_2, and either oxygen or carbon dioxide emissions. Excluding exempted time periods, if any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.[401 KAR 61:005, Section 3; 40 CFR 60, Appendix B, Performance Specification 2; 40 CFR 75, control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation from the monitoring system requirements [40 CFR 63.10020(d)].

j. The permittee shall measure NO_X emissions using CEMS to demonstrate compliance with the applicable NO_X emission limits under 401 KAR 51:017. The 30-day rolling average for EU2 will be calculated at the end of each boiler operating day as the sum of NO_X mass (lbs) including non-operational hours divided by the sum of the heat input (MMBtu) for 30 consecutive boiler operating days. The 24 hour block average for EU1 and EU2 combined will be calculated at the end of each boiler operating day as the sum of NO_X mass (lbs) including non-operational hours divided by 24 hours. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 2; 40 CFR 75, Appendix A; and 401 KAR 52:020, Section 10]

~~j.~~ The permittee shall use approved CEMS methodologies or other calculation methodologies of 40 CFR Part 75 Appendix G to demonstrate compliance with the applicable CO_2 emission limit under 401 KAR 51:017. The annual rolling average will be calculated at the end of each calendar month as the sum of monthly CO_2 mass (lbs) including non-operational periods divided by the sum of MWh-g output (MWh) for 12 consecutive months. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 3; 40 CFR 75, Appendix A; 40 CFR 75, Appendix G; and 401 KAR 52:020, Section 10]

5. **Specific Recordkeeping Requirements:**

a. The permittee shall maintain a file of all information reported in the quarterly summaries, with the exception that records shall be maintained for 5 years. [401 KAR 61:005, Section 3(15)(g); 401 KAR 61:015, Section 6(4); and 401 KAR 52:020, Section 10]

b. The permittee shall maintain records of:

i. The sulfur content from each fuel analysis;

ii. The rate of fuel burned for each fuel type, on a daily basis;

iii. The heating value and ash content on a weekly basis;

iv. The average electrical output and the minimum and maximum hourly generation rate on a daily basis;

v. When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted;

vi. Data collected either by the continuous monitoring systems or as necessary to convert monitoring data to the units of the applicable standard;

vii. Results of all compliance tests; and

viii. Percentage of the CEM data (excluding exempted time periods) showing excursions above the PM standard and the PM indicator level.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ix. NO_X and O_2/CO_2 CEMS data to demonstrate compliance with the applicable limits under 401 KAR 51:017

[401 KAR 52:020, Section 10]

c. The permittee shall maintain records of U.S. EPA Reference Method 9 readings in a designated logbook and/or electronic format. Records shall be maintained for five years. [401 KAR 52:020, Section 10]

d. In the event of start-up, the permittee shall maintain records of: [401 KAR 52:020, Section 10 and 401 KAR 61:015]

i. The duration of start-up;

ii. The type of start-up (cold, warm, or hot); and

iii. Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

e. The permittee shall keep records according to 40 CFR 63.10032(a)(1) and (2). If required or electing to continuously monitor Hg and/or HCl and/or HF emissions, the permittee shall also keep the records required under 40 CFR 63, Subpart UUUUU, Appendix A and/or Appendix B. [40 CFR 63.10032(a)]

i. A copy of each notification and report submitted to comply with 40 CFR 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted according to the requirements in 40 CFR 63.10(b)(2)(xiv) [40 CFR 63.10032(a)(1)].

ii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii) [40 CFR 63.10032(a)(2)].

f. For each CEMS and CPMS used for 40 CFR 63, Subpart UUUUU, the permittee shall keep records according to 40 CFR 63.10032(b)(1) through (4) [40 CFR 63.10032(b)].

i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi) [40 CFR 63.10032(b)(1)].

ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3) {40 CFR 63.10032(b)(2)].

iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i) [40 CFR 63.10032(b)(3)].

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period [40 CFR 63.10032(b)(4)].

g. The permittee shall keep the records required in Table 7 to 40 CFR 63, Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. The permittee shall submit reports to U.S. EPA as required by 40 CFR 63.10031(f).

f. See Section F – Monitoring, Recordkeeping, and Reporting Requirements.

7. Specific Control Equipment Operating Conditions:

a. The pulse jet fabric filter baghouse shall be continuously operated to maximize PM emission reductions, consistent with manufacturer's specification, the operational design and maintenance limitations of the units, and good engineering practice. [Consent Decree entered September 24, 2007, Section VII.A]

b. During 100% natural gas firing, the DFGD and PJFF are not required to be operated. [401 KAR 51:017]

c. Beginning on December 31, 2012, the permittee shall continuously operate the SCR at all times that Unit 2 is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the SCR for minimizing emissions to the extent practicable. [Consent Decree entered September 24, 2007, paragraph 55]

~~a.~~d. During 100% natural gas firing, the permittee shall operate the SCR on Unit 2 to ensure compliance with 2. Emission Limitations (g) and in accordance with Section E. [401 KAR 51:017]

~~b.~~e. Beginning on June 30, 2012, the permittee shall continuously operate the FGD at all times that Unit 2 is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the FGD or equivalent technology, for minimizing emissions to the extent practicable. [Consent Decree entered September 24, 2007, paragraph 67]

~~c.~~f. The permittee shall maintain records regarding the maintenance of the control equipment. [401 KAR 52:020, Section 10]

~~d.~~g. See **Section E – Source Control Equipment Requirements**.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 03:	**Coal Handling Operations**
Description:	Truck and railcar unloading, receiving hoppers (two), coal conveyers/transfer points (five), reclaim hoppers, crusher (one), coal stacker, coal stockpile, and yard area.
Maximum Continuous Rating:	600 tons/hr
Control Devices:	DusTreat CF9156 and DusTreat DC6109; additives to reduce fugitive emissions.
Construction Commenced:	Prior to 1970

APPLICABLE REGULATIONS:
401 KAR 63:010, *Fugitive emissions*

1. **Operating Limitations:**
The permittee shall not cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following: [401 KAR 63:010, Section 3(1)]
   a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land; [401 KAR 63:010, Section 3(1)(a)]
   b. Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts; [401 KAR 63:010, Section 3(1)(b)]
   c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or similar operations. [401 KAR 63:010, Section 3(1)(c)]
   d. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; [401 KAR 63:010, Section 3(1)(d)]
   e. The maintenance of paved roadways in a clean condition; [401 KAR 63:010, Section 3(1)(e)]
   f. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water. [401 KAR 63:010, Section 3(1)(f)]
   g. Upon Commercial Operation Date of the Cooper Project (refer to applicable definitions in Section D.5), the permittee shall limit the annual coal throughput of Emission Unit 03 to 463,566 tpy. [401 KAR 51:017 Section 9]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements (b)** and **5. Specific Recordkeeping Requirements (b)**.

Permit Number: V-18-027

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 07:	**Coal Crushing Facility (Run of Mine Coal Handling Facility)**
Description:	Equipment includes: A & T Model 425 Feeder, Crusher Feeder Conveyor, Jeffrey Model 59FT Flextooth Crusher, Crushed Coal Conveyor and Discharge Chute
Maximum Continuous Rating:	400 tons/hr
Construction Commenced:	December 1998

APPLICABLE REGULATIONS:
401 KAR 60:005, Section 2(2)(gg), 40 C.F.R. 60.250 to 60.258 (**Subpart Y**), *Standards of Performance for Coal Preparation and Processing Plants*

1. **Operating Limitations:**

   Upon Commercial Operation Date of the Cooper Project modifications (refer to applicable definitions in Section D.5), the permittee shall limit the annual coal throughput of Emission Unit 07 to 463,566 tpy. [401 KAR 51:017 Section 9]
   ~~N/A~~

2. **Emission Limitations:**
   The permittee shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater. [40 CFR 60.254(a)]

3. **Testing Requirements:**
   The permittee shall determine opacity on a monthly basis using U.S. EPA Reference Method 9 of Appendix A-4 and the procedures in 40 CFR 60.11 as specified in 40 CFR 60.257(a)(1) through (3). [40 CFR 60.255]

4. **Specific Monitoring Requirements:**
   a. The permittee shall perform a qualitative visual observation of the emissions from each unit on a weekly basis while in operation. If visible emissions are present, then the opacity shall be determined by U.S. EPA Reference Method 9. [401 KAR 52:020, Section 10]

   b. The permittee shall monitor the amount of coal (tons) processed on a monthly basis. [401 KAR 52:020, Section 10]

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of weekly qualitative visual observations and any U.S. EPA Reference Method 9 readings performed. [401 KAR 52:020, Section 10]

   b. The permittee shall maintain records of the amount of coal (tons) processed on a monthly basis. [401 KAR 52:020, Section 10]

   c. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

6. **Specific Reporting Requirements:**
   See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 17, 23, and 24: Natural Gas-Fired Dew Point Preheaters

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
17	Dew Point Heater No. 1	TBD	11.65 MMBtu/hr	Natural Gas
23	Dew Point Heater No. 2	TBD	9.13 MMBtu/hr	Natural Gas
24	Dew Point Heater No. 3	TBD	9.13 MMBtu/hr	Natural Gas

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 59:015, *New indirect heat exchangers*

401 KAR 60:005, Section (2)(2)(d), 40 C.F.R. 60.40c to 60.48c (**Subpart Dc**), *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* (EU 17 only)

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*

1. **Operating Limitations:**
   a. EU 17, 23, 24: The permittee shall complete an annual or 5-year tune-up as applicable as specified in 40 CFR 63.7540. [40 CFR 63.7500(c) referencing Items 1 and 3 of 40 CFR 63, Subpart DDDDD, Table 3]

   b. EU 17, 23, 24: At all times, the permittee shall operate and maintain any affected source (as defined in 40 CFR 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Division that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]

   c. EU 17, 23, 24: Fuel Gas (Dewpoint) Heaters (EU 17, 23, and 24) are units designed to burn gas 1 fuels, they are not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 15, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4. [40 CFR 63.7500(e)]

   d. EU 17, 23, 24: The permittee shall demonstrate initial compliance with the applicable work practice standards in 40 CFR 63, Subpart DDDDD, Table 3 within the applicable annual or biennial schedule as specified in 40 CFR 63.7515(d) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the permittee is required to complete the annual or biennial tune-up as specified in 40 CFR 63.7515(d). [40 CFR 63.7510(g), 63.7540(a)(10), and 63.7540(a)(11)]

e. EU 17: The permittee shall conduct an annual performance tune-up for EU 17 according to 40 CFR 63.7540(a)(10). Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be conducted no more than 13 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 CFR 63.7515(d), 63.7540(a)(10), and 63.7540(a)(13)]

f. EU 23, 24: The permittee shall conduct a biennial performance tune-up for EU 23 and EU 24 according to 40 CFR 63.7540(a)(11). Each biennial tune-up specified in 40 CFR 63.7540(a)(11) shall be conducted no more than 25 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 CFR 63.7515(d), 63.7540(a)(11), and 63.7540(a)(13)]

g. EU 17, 23, 24: The permittee shall conduct required annual or biennial tune-ups of the boiler or process heaters as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance.. [40 CFR 63.7540(a)(10), 40 CFR 63.7540(a)(11]

   i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment; [40 CFR 63.7540(a)(10)(i)]

   ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available; [40 CFR 63.7540(a)(10)(ii)]

   iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. [40 CFR 63.7540(a)(10)(iii)]

   iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject. [40 CFR 63.7540(a)(10)(iv)]

   v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and [40 CFR 63.7540(a)(10)(v)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

vi. Maintain on-site and submit, if requested by the Division, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C), [40 CFR 63.7540(a)(10)(vi)]

1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; [40 CFR 63.7540(a)(10)(vi)(A)]

2. A description of any corrective actions taken as part of the tune-up; and [40 CFR 63.7540(a)(10)(vi)(B)]

3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit. [40 CFR 63.7540(a)(10)(vi)(C)]

h. EU 17, 23, 24: If the boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the permittee must conduct a tune-up of the boiler or process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The permittee may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the permittee must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the permittee shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. [40 CFR 63.7540(a)(12)]

i. EU 17, 23, 24: During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii). [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)]

j. EU 17, 23, 24: The permittee shall limit emissions through the use of low-NO_X burners and good combustion and operating practices. [401 KAR 51:017]

k. EU 17, 23, 24: The permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf to control emissions of H_2SO_4 PM, PM_{10}, and $PM_{2.5}$. [401 KAR 51:017]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **<u>Section D.4.</u>**

2. **<u>Emissions Limitations:</u>**

a. The permittee shall not allow the emissions of NO_X, CO, VOC, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Emission Unit	Pollutant	Emission Limit	Averaging Period
EU 17, 23, 24	NO_X	0.05 lb/MMBtu	3-hr
EU 17, 23, 24	CO	0.082 lb/MMBtu	3-hr
EU 17, 23, 24	VOC	0.0054 lb/MMBtu	3-hr

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

EU 17, 23, 24	CO_2e	117.1 lb/MMBtu	Fuel Spec.

Compliance Demonstration Method:
Compliance with the emissions limitations shall be demonstrated via **1. Operating Limitations (j)**

b. An affected facility shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)]

c. An affected facility shall not cause emissions of particulate matter in excess of twenty percent opacity, except: [401 KAR 59:015, Section 4(2)]

   i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes; [401 KAR 59:015, Section 4(2)(a)]

   ii. For emissions from an affected facility caused by building a new fire, emissions during the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 59:015, Section 4(2)(c)]

d. An affected facility shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu [401 KAR 59:015, Section 5(1)(b)1.]

Compliance Demonstration Method:

These units are assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas. [401 KAR 50:045, Section 4(3)(c)1.]

3. Testing Requirements:

a. Testing shall be conducted at such times as may be requested by the Cabinet in accordance with 401 KAR 50:045, Section 4.

4. Specific Monitoring Requirements:

a. EU17: The permittee shall monitor natural gas usage (MMscf) on a monthly basis [401 KAR 52:020, Section 10; EU 17: 40 CFR 60.48c(g)(2)].

5. Specific Recordkeeping Requirements:

a. EU 17: The permittee shall maintain records of natural gas usage (MMscf) on a monthly basis. [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)]

b. EU 17: All records required under 40 CFR 60.48c shall be maintained by the permittee for a period of two years following the date of such record. [40 CFR 60.48c(i)]

c. EU 17, 23, 24: The permittee shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.7555(a)(1)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d. EU 17, 23, 24: If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under 40 CFR Part 63, other gas 1 fuel, or gaseous fuel subject to another subpart of 40 CFR Part 63 or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

e. EU 17, 23, 24: Records of notifications and reports submitted to comply with 40 CFR 63, Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). [40 CFR 63.7560(a)]

   i. As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.7560(b)]

   ii. The permittee shall keep each record on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. [40 CFR 63.7560(c)]

6. **Specific Reporting Requirements:**

a. EU 17, 23, 24: The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD. [40 CFR 63.7495(d)]

b. EU 17, 23, 24: The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 7545(e). [40 CFR 63.7530(f)]

c. EU 17, 23, 24: The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550. [40 CFR 63.7540(b)]

d. EU 17, 23, 24: The permittee shall submit to the Division all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified. [40 CFR 63.7545(a)]

e. EU 17, 23, 24: As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. [40 CFR 63.7545(c)]

f. EU 17, 23, 24: The permittee shall submit the Notification of Compliance Status report that contains the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b). [40 CFR 63.7545 (e)]

i. A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration. [40 CFR 63.7545(e)(1)]

ii. In addition to information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certification of compliance, as applicable, and signed by a responsible official: [40 CFR 63.7545(e)(8)]

1. "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi)." [40 CFR 63.7545(e)(8)(i)]

g. EU 17, 23, 24: If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of 40 CFR 63, 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5). [40 CFR 63.7545(f)]

i. Company name and address. [40 CFR 63.7545(f)(1)]

ii. Identification of the affected unit. [40 CFR 63.7545(f)(2)]

iii. Reason the permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began. [40 CFR 63.7545(f)(3)]

iv. Type of alternative fuel that the permittee intends to use. [40 CFR 63.7545(f)(4)]

v. Dates when the alternative fuel use is expected to begin and end. [40 CFR 63.7545(f)(5)]

h. EU 17, 23, 24: The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies. [40 CFR 63.7550(a)]

i. EU 17, 23, 24: The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4): [40 CFR 63.7550(b)]

i. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495. [40 CFR 63.7550(b)(1)]

ii. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(2)]

iii. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5- year periods from January 1 to December 31. [40 CFR 63.7550(b)(3)]

iv. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(4)]

v. For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4). [40 CFR 63.7550(b)(5)]

j. EU 17, 23, 24: The permittee shall submit a compliance report with the information in 40 CFR 63.7550(c)(5)(i) through (iii), (xiv), and (xvii): [40 CFR 63.7550(c)(1)]

i. Company and Facility name and address. [40 CFR 63.7550(c)(5)(i)]

ii. Process unit information, emission limitations, and operating parameter limitations. [40 CFR 63.7550(c)(5)(ii)]

iii. Date of report and beginning and ending dates of the reporting period. [40 CFR 63.7550(c)(5)(iii)]

iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)]

v. Statement by a responsible official with that official’s name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [40 CFR 63.7550(c)(5)(xvii)]

k. EU 17, 23, 24: The permittee shall submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3), as applicable. [40 CFR 63.7550(h)]

i. Within 60 days after the date of completing each performance test (as defined in 40 CFR 63.2) required by this subpart, the permittee must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either 40 CFR 63.7550(h)(1)(i) or (ii). [40 CFR 63.7550(h)(1)]

ii. The permittee must submit all reports required by Table 9 of 40 CFR 63, Subpart DDDDD electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Division at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. [40 CFR 63.7550(h)(3)]

l. EU 17: The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.48c(a)]

i. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility. [40 CFR 60.48c(a)(1)]
ii. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c, or 60.43c. [40 CFR 60.48c(a)(2)]
iii. The annual capacity factor at which the permittee anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired. [40 CFR 60.48c(a)(3)]
iv. Notification if an emerging technology will be used for controlling SO_2 emissions. The District will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the District may require the permittee of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of 40 CFR 60.42c(a) or (b)(1), unless and until this determination is made by the District. [40 CFR 60.48c(a)(4)]

m. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 20:	**Natural Gas-Fired Auxiliary Boiler**
Primary Fuel:	Natural Gas
Continuous Rating:	78.3 MMBtu/hr
Construction Commenced:	TBD

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 59:015, *New indirect heat exchangers*

401 KAR 60:005, Section (2)(2)(d), 40 C.F.R. 60.40c to 60.48c (**Subpart Dc**), *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

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*

1. **Operating Limitations:**
   a. The permittee shall complete an annual or 5-year tune-up as applicable as specified in 40 CFR 63.7540. [40 CFR 63.7500(c) referencing Items 1 and 3 of 40 CFR 63, Subpart DDDDD, Table 3]

   b. At all times, the permittee shall operate and maintain any affected source (as defined in 40 CFR 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Division that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.7500(a)(3)]

   c. Because the Auxiliary Boiler (EU 20) is a unit designed to burn gas 1 fuels, it is not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 15, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4. [40 CFR 63.7500(e)]

   d. The permittee shall demonstrate initial compliance with the applicable work practice standards in 40 CFR 63, Subpart DDDDD, Table 3 within the applicable annual or biennial schedule as specified in 40 CFR 63.7515(d) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the permittee is required to complete the annual or biennial tune-up as specified in 40 CFR 63.7515(d). [40 CFR 63.7510(g), 63.7540(a)(10), and 63.7540(a)(11)]

   e. The permittee shall conduct an annual performance tune-up according to 40 CFR 63.7540(a)(10). Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be conducted no more than 13 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 CFR 63.7515(d), 63.7540(a)(10), and 63.7540(a)(13)]

   f. The permittee shall conduct required annual or biennial tune-ups of the boiler or process heaters as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. [40 CFR 63.7540(a)(10), 40 CFR 63.7540(a)(11]

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment; [40 CFR 63.7540(a)(10)(i)]

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available; [40 CFR 63.7540(a)(10)(ii)]

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. [40 CFR 63.7540(a)(10)(iii)]

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject. [40 CFR 63.7540(a)(10)(iv)]

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and [40 CFR 63.7540(a)(10)(v)]

vi. Maintain on-site and submit, if requested by the Division, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C), [40 CFR 63.7540(a)(10)(vi)]

1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; [40 CFR 63.7540(a)(10)(vi)(A)]

2. A description of any corrective actions taken as part of the tune-up; and [40 CFR 63.7540(a)(10)(vi)(B)]

3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit. [40 CFR 63.7540(a)(10)(vi)(C)]

g. If the boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the permittee must conduct a tune-up of the boiler or process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The permittee may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the permittee must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the permittee shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. [40 CFR 63.7540(a)(12)]

h. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii). [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)]

i. The permittee shall limit emissions through the use of ultra low-NO_X burners, oxidation catalyst, and good combustion and operating practices. [401 KAR 51:017]

j. The permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf to control emissions of H_2SO_4 PM, PM_{10}, and $PM_{2.5}$. [401 KAR 51:017]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **Section D.4.**

2. Emissions Limitations:

a. The permittee shall not allow the emissions of NO_X, CO, VOC, H_2SO_4, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Emission Unit	Pollutant	Emission Limit	Averaging Period
EU 20	NO_X	0.011 lb/MMBtu	3-hr
EU 20	CO	0.003 lb/MMBtu	3-hr
EU 20	VOC	0.0054 lb/MMBtu	3-hr
EU 20	CO_2e	117.1 lb/MMBtu	Fuel Spec.

Compliance Demonstration Method:

b. Compliance with the NO_X and CO emissions limitations shall be demonstrated by an initial performance test as specified in **3. Testing Requirements (a and b)**.

c. Compliance with the VOC and CO_2e emission limits shall be demonstrated via **1. Operating Limitations (i)**

d. An affected facility shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)]

e. An affected facility shall not cause emissions of particulate matter in excess of twenty percent opacity, except: [401 KAR 59:015, Section 4(2)]

   i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes; [401 KAR 59:015, Section 4(2)(a)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ii. For emissions from an affected facility caused by building a new fire, emissions during the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 59:015, Section 4(2)(c)]

f. An affected facility shall not cause emissions of sulfur dioxide in excess of 0.8lb/MMBtu [401 KAR 59:015, Section 5(1)(b)1.]

Compliance Demonstration Method:

These units are assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas. [401 KAR 50:045, Section 4(3)(c)1.]

3. **Testing Requirements:**

a. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable NO_X emission limit under 401 KAR 51:017 using EPA Method 7 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

b. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable CO emission limit under 401 KAR 51:017 using EPA Method 10 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

4. **Specific Monitoring Requirements:**

a. The permittee shall monitor natural gas usage (MMscf) on a monthly basis [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)].

5. **Specific Recordkeeping Requirements:**

a. The permittee shall maintain records of natural gas usage (MMscf) on a monthly basis. [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)]

b. All records required under 40 CFR 60.48c shall be maintained by the permittee for a period of two years following the date of such record. [40 CFR 60.48c(i)]

c. The permittee shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.7555(a)(1)]

d. If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under 40 CFR Part 63, other gas 1 fuel, or gaseous fuel subject to another subpart of 40 CFR Part 63 or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies. [40 CFR 63.7555(h)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. Records of notifications and reports submitted to comply with 40 CFR 63, Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). [40 CFR 63.7560(a)]

   i. As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.7560(b)]

   ii. The permittee shall keep each record on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. [40 CFR 63.7560(c)]

6. **Specific Reporting Requirements:**

a. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD. [40 CFR 63.7495(d)]

b. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 7545(e). [40 CFR 63.7530(f)]

c. The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550. [40 CFR 63.7540(b)]

d. The permittee shall submit to the Division all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified. [40 CFR 63.7545(a)]

e. As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. [40 CFR 63.7545(c)]

f. The permittee shall submit the Notification of Compliance Status report that contains the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b). [40 CFR 63.7545 (e)]

   i. A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration. [40 CFR 63.7545(e)(1)]

ii. In addition to information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certification of compliance, as applicable, and signed by a responsible official: [40 CFR 63.7545(e)(8)]

"This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi)." [40 CFR 63.7545(e)(8)(i)]

g. If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of 40 CFR 63, 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5). [40 CFR 63.7545(f)]

i. Company name and address. [40 CFR 63.7545(f)(1)]

ii. Identification of the affected unit. [40 CFR 63.7545(f)(2)]

iii. Reason the permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began. [40 CFR 63.7545(f)(3)]

iv. Type of alternative fuel that the permittee intends to use. [40 CFR 63.7545(f)(4)]

v. Dates when the alternative fuel use is expected to begin and end. [40 CFR 63.7545(f)(5)]

h. The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies. [40 CFR 63.7550(a)]

i. The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4): [40 CFR 63.7550(b)]

i. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495. [40 CFR 63.7550(b)(1)]

ii. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(2)]

iii. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. [40 CFR 63.7550(b)(3)]

iv. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31. [40 CFR 63.7550(b)(4)]

v. For each affected source that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4). [40 CFR 63.7550(b)(5)]

j. The permittee shall submit a compliance report with the information in 40 CFR 63.7550(c)(5)(i) through (iii), (xiv), and (xvii): [40 CFR 63.7550(c)(1)]

i. Company and Facility name and address. [40 CFR 63.7550(c)(5)(i)]

ii. Process unit information, emission limitations, and operating parameter limitations. [40 CFR 63.7550(c)(5)(ii)]

iii. Date of report and beginning and ending dates of the reporting period. [40 CFR 63.7550(c)(5)(iii)]

iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)]

v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [40 CFR 63.7550(c)(5)(xvii)]

k. The permittee shall submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3), as applicable. [40 CFR 63.7550(h)]

i. Within 60 days after the date of completing each performance test (as defined in 40 CFR 63.2) required by this subpart, the permittee must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either 40 CFR 63.7550(h)(1)(i) or (ii). [40 CFR 63.7550(h)(1)]

ii. The permittee must submit all reports required by Table 9 of 40 CFR 63, Subpart DDDDD electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Division at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. [40 CFR 63.7550(h)(3)]

l. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.48c(a)]

   i. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility. [40 CFR 60.48c(a)(1)]
   ii. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c, or 60.43c. [40 CFR 60.48c(a)(2)]
   iii. The annual capacity factor at which the permittee anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired. [40 CFR 60.48c(a)(3)]
   iv. Notification if an emerging technology will be used for controlling SO_2 emissions. The District will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the District may require the permittee of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of 40 CFR 60.42c(a) or (b)(1), unless and until this determination is made by the District. [40 CFR 60.48c(a)(4)]

m. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 29A and 29B: Natural Gas-Fired HVAC Units

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
29A	7 HVAC Heaters	TBD	5.5 MMBtu/hr	Natural Gas
29B	14 HVAC Heaters	TBD	0.061 MMBtu/hr	Natural Gas

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 59:015, *New indirect heat exchangers*

1. **Operating Limitations:**

   a. For all units with maximum continuous heat input ratings equal to or greater than 1 MMBtu/hr, during a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)]

   b. The permittee shall limit the emissions from the HVAC heaters via use of good combustion and operating practices. [401 KAR 51:017]

   c. The permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf to control emissions of H_2SO_4, PM, PM_{10}, and $PM_{2.5}$. [401 KAR 51:017]

   Compliance Demonstration Method:
   Compliance shall be demonstrated according to **Section D.4.**

2. **Emissions Limitations:**

   a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Pollutant	Emission Limit	Averaging Period
NO_X	0.1 lb/MMBtu	3-hr
CO	0.082 lb/MMBtu	3-hr
VOC	0.005 lb/MMBtu	3-hr
CO_2e	117.1 lb/MMBtu	Fuel Spec.

   Compliance Demonstration Method:

   Compliance with the NO_X, CO, VOC, and CO_2e emissions limitations shall be demonstrated via via 1. **Operating Limitations (b)**

   b. An affected facility shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu

[401 KAR 59:015, Section 4(1)(b)]

c. An affected facility shall not cause emissions of particulate matter in excess of twenty percent opacity, except: [401 KAR 59:015, Section 4(2)]

   i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes; [401 KAR 59:015, Section 4(2)(a)]

   ii. For emissions from an affected facility caused by building a new fire, emissions during the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 59:015, Section 4(2)(c)]

d. An affected facility shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu [401 KAR 59:015, Section 5(1)(b)1.]

Compliance Demonstration:

These units are assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas. [401 KAR 50:045, Section 4(3)(c)1.]

3. **Testing Requirements:**
   a. Testing shall be conducted at such times as may be requested by the Cabinet in accordance with 401 KAR 50:045, Section 4.

4. **Specific Monitoring Requirements:**
   a. The permittee shall monitor natural gas usage (MMscf) on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of natural gas usage (MMscf) on a monthly basis. [401 KAR 52:020, Section 10]

6. **Specific Reporting Requirements:**
   a. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 18 and 19 Gas Turbines with HRSG

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Control Equipment
18	Combined Cycle Gas Turbine (CCGT)	TBD	2,734 MMBtu/hr for Natural Gas 2,597 MMBtu/hr for ULSFO	Natural Gas ULSFO	SCR, Oxidation Catalyst
19	Combined Cycle Gas Turbine (CCGT)	TBD	2,734 MMBtu/hr for Natural Gas 2,597 MMBtu/hr for ULSFO	Natural Gas ULSFO	SCR, Oxidation Catalyst

Applicable Regulations:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 52:060, *Acid rain permits,* incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J).

401 KAR 60:005, Section 2(2)(ffff), implementing **40 CFR 60, Subpart KKKK**, *Standards of Performance for Stationary Combustion Turbines*;

401 KAR 60:005, Section 2(2)(jjjj), implementing **40 CFR 60, Subpart TTTTa,** *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* **[NOTE: Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit language is not provided];**

401 KAR 63:002, Section 2(4)(dddd), implementing **40 CFR 63, Subpart YYYY**, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.*

40 CFR 97, Subpart AAAAA, *CSAPR NO_x Annual Trading Program*

40 CFR 97, Subpart CCCCC, *CSAPR SO_2 Group 1 Trading Program*

40 CFR 97, Subpart EEEEE, *CSAPR NO_x Ozone Season Group 2 Trading Program*

1. **Operating Limitations:**
   a. At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Division which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6105(c); 40 CFR

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

60.4333(a)]

b. The period of time for turbine startup is subject to the limits specified in the definition of startup in 40 CFR 63.6175, where startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. For combined cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 3 hours, whichever is less. Turbines in combined cycle configurations that are operating as simple cycle turbines must meet the startup requirements for simple cycle turbines while operating as simple cycle turbines. [40 CFR 63.6100, 40 CFR 63.175, and Table 1, Item 1, of 40 CFR 63, Subpart YYYY]

c. The permittee must maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR 63.6100, 63.6140, and Table 2, Item 1, of 40 CFR 63, Subpart YYYY]

d. The permittee must comply with the emissions limitations and operating limitations in 40 CFR 63, Subpart YYYY upon startup of the affected source. [40 CFR 63.6095(a)(4)]

e. When firing natural gas, the permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/Cscf to control emissions of H_2SO_4 and $PM/PM_{10}/PM_{2.5}$ [401 KAR 51:017]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **Section D.4.**

f. When firing fuel oil, the permittee shall utilize fuel oil with a maximum sulfur content of 15 ppm to control emissions of H_2SO_4 and $PM/PM_{10}/PM_{2.5}$ [401 KAR 51:017]

Compliance Demonstration Method:
Compliance shall be demonstrated according to **Section D.4.**

g. The permittee shall utilize good combustion and operating practices to control emissions of $PM/PM_{10}/PM_{2.5}$ and CO_2. [401 KAR 51:017]

2. **Emission Limitations:**

a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, CO_2, and CO_2e to exceed the limits in the following table from each CCGT. [401 KAR 51:017]

Fuel	Pollutant	Emission Limit	Averaging Period
Natural Gas	NO_X	2 ppmvd at 15% O_2	30-day†
	CO	2 ppmvd at 15% O_2	30-day†

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

	VOC	1 ppmvd at 15% O_2	3-hr†
	$PM/PM_{10}/PM_{2.5}$	17.21 lb/hr	3-hr*
	H_2SO_4	0.5 gr S/100 scf	Annual
	CO_2	800 lb/MWh-g	Annual*
Fuel Oil	NO_X	4.5 ppmvd at 15% O_2	30-day†
	CO	2 ppmvd at 15% O_2	30-day†
	VOC	1 ppmvd at 15% O_2	3-hr†
	$PM/PM_{10}/PM_{2.5}$	30.12 lb/hr	3-hr*
	H_2SO_4	15 ppm total sulfur	Per shipment
	CO_2	1,250 lb/MWh-g	Annual*
Both Fuels	NO_X	165 tpy	Annual*
	CO	2,390 tpy	Annual*
	VOC	226 tpy	Annual*

† For short-term NO_X, CO, VOC emission limits, during steady-state operation, exclude any data recorded during periods of startup and shutdown
* For annual NO_X, CO, and VOC emission limits and $PM/PM_{10}/PM_{2.5}$ and CO_2 emission limits, include periods of startup and shutdown.

Compliance Demonstration Method:
Compliance shall be demonstrated according to **1. Operating Limitations (e and f)**, **3. Testing Requirements (g and h)**, and **4. Specific Monitoring Requirements(h and i)**, and **5. Specific Recordkeeping Requirements (e)**. The permittee shall calculate monthly NO_X, CO, and VOC emissions and maintain a 12-month rolling total. Monthly NO_X and CO emissions shall be determined for Emission Units 18 and 19 using CEMS. Monthly VOC emissions shall be determined for Emission Units 18 and 19 using monthly fuel usage and emission factors derived from performance testing.

b. EU18 and EU19 (Combustion Turbines), which have a combustion turbine heat input at peak load (HHV) greater than 850 MMBtu/hr, shall meet an emission limit of 15 parts per million (ppm) at 15% oxygen (O_2); or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)), when firing natural gas, based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)). Pursuant to Table 1 of 40 CFR 60, Subpart KKKK, as a new CT when firing fuels other than natural gas, electric generating, EU18 and EU19 shall meet an emission limit of 42 ppm at 15% O_2; or 160 ng/J of useful output (1.3 lb/MWh). If the total heat input is greater than or equal to 50 percent natural gas, the permittee must meet the corresponding limit for a natural gas-fired turbine when burning that fuel. Similarly, when the total heat input is greater than 50 percent distillate oil and fuels other than natural gas, the permittee must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time the permittee burns that particular fuel. [40 CFR 60.4320, 40 CFR 60.4325, and 40 CFR 60, Subpart KKKK, Table 1]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. Turbines operating at less than 75 percent peak load that have a combustion turbine heat input at peak load (HHV) greater than 30 MW output or turbines operating at temperatures less than 0 degrees F that are greater than 30 MW output shall meet an emission limit of 96 ppm at 15% O_2; or 590 ng/J of useful output (4.7 lb/MWh), based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)). [40 CFR 60.4320, and 40 CFR 60, Subpart KKKK, Table 1]

d. The permittee shall not burn in the subject stationary combustion turbine (EU18 and EU19) any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [40 CFR 60.4330(a)(2)]

e. EU18 and EU19, which are lean premix gas-fired stationary combustion turbines as defined in 40 CFR 63.6175, must limit the concentration of formaldehyde in the exhaust to 91 ppbvd or less at 15-percent O_2, except during turbine startup. [40 CFR 63.6100 and Table 1, Item 1, of 40 CFR 63, Subpart YYYY]

f. To preclude the applicability of 401 KAR 51:017, Sections 8 through 16, for SO2 comply with the emission limitation and compliance demonstration methodology specified in the EU02 section of this permit.

Compliance Demonstration:
Compliance **2. Emission Limitations(a & g)** shall be demonstrated according to **3. Testing Requirements(a-f), 4. Specific Monitoring Requirements(a-g), 5. Specific Recordkeeping Requirements(a-d)** and **6. Specific Reporting Requirements(a-o)**.

3. Testing Requirements:

a. If the permittee elects to install and certify a NO_X-diluent CEMS under 40 CFR 60.4345, then the initial performance test required under 40 CFR 60.8 may be performed in the following alternative manner: [40 CFR 60.4405]

   i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs. [40 CFR 60.4405(a)]

   ii. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit. [40 CFR 60.4405(b)]

   iii. Use the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR 60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.4335. [40 CFR 60.4405(c)]

   iv. Compliance with the applicable emission limit in 40 CFR 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit. [40 CFR 60.4405(d)]

b. The performance test must be done at any load condition within plus or minus 25 percent of

100 percent of peak load. The permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The permittee must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes. [40 CFR 60.4400(b)]

i. Compliance with the applicable emission limit in 40 CFR 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR 60.4320. [40 CFR 60.4400(b)(4)]

ii. If the permittee elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit. [40 CFR 60.4400(b)(5)]

iii. The ambient temperature must be greater than 0 °F during the performance test. [40 CFR 60.4400(b)(6)]

c. The permittee must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of 40 CFR 63, Subpart YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in 40 CFR 63.6095 and according to the provisions in 40 CFR 63.7(a)(2). [40 CFR 63.6110(a)]

d. The permittee is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in 40 CFR 63.6110(b)(1) through (b)(5). [40 CFR 63.6110(b)]

i. The test must have been conducted using the same methods specified in 40 CFR 63, Subpart YYYY, and these methods must have been followed correctly. [40 CFR 63.6110(b)(1)]

ii. The test must not be older than 2 years. [40 CFR 63.6110(b)(2)]

iii. The test must be reviewed and accepted by the Division. [40 CFR 63.6110(b)(3)]

iv. Either no process or equipment changes must have been made since the test was performed, or the permittee must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes. [40 CFR 63.6110(b)(4)]

v. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load. [40 CFR 63.6110(b)(5)]

e. Subsequent performance tests for formaldehyde must be performed on an annual basis as specified in Table 3 of 40 CFR 63, Subpart YYYY. [40 CFR 63.6115]

f. The permittee must conduct each performance test in Table 3 of 40 CFR 63, Subpart YYYY that applies. [40 CFR 63.6120(a)]

i. Each performance test must be conducted according to the requirements in Table 3 of 40

CFR 63, Subpart YYYY. [40 CFR 63.6120(b)]

ii. Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. Performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The owner or operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Division such records as may be necessary to determine the conditions of performance tests. [40 CFR 63.6120(c)]

iii. The permittee must conduct three separate test runs for each formaldehyde performance test, and each test run must last at least 1 hour. [40 CFR 63.6120(d)]

g. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable VOC emission limit under 401 KAR 51:017 using EPA Method 18, 25, or 25A or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

h. The permittee shall conduct an initial performance test to demonstrate with compliance with the applicable PM/PM_{10}/$PM_{2.5}$ emission limit under 401 KAR 51:017 by testing filterable and condensable PM using EPA Method 5 and 202 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017]

4. **Specific Monitoring Requirements:**

a. As an alternative to performing annual performance tests, the permittee may install, maintain, calibrate and operate one of the following continuous monitoring systems: [40 CFR 60.4340(b)]

i. Continuous emission monitoring as described in 40 CFR 60.4335(b) and 60.4345. [40 CFR 60.4340(b)(1)]

ii. Pursuant to 40 CFR 60.4335(b), the permittee may

1. Install, certify, maintain, and operate a CEMS consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in ppm or lb/MMBtu; and [40 CFR 60.4335(b)(1)]

2. For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and [40 CFR 60.4335(b)(2)]

3. For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and [40 CFR 60.4335(b)(3)]

4. For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate,

temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h). [40 CFR 60.4335(b)(4)]

b. Pursuant to 40 CFR 60.4340(b)(1), the NO_X CEMS shall meet the following requirements: [40 CFR 60.4345]

i. Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to 40 CFR 60, except the 7-day calibration drift is based on unit operating days, not calendar days. With Division approval, Procedure 1 in appendix F to 40 CFR 60 is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of 40 CFR 75 is acceptable for use. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis. [40 CFR 60.4345(a)]

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour. [40 CFR 60.4345(b)]

iii. Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with Division approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable for use. [40 CFR 60.4345(c)]

iv. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions. [40 CFR 60.4345(d)]

v. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in 40 CFR 60.4345(a), (c), and (d). For the CEMS and fuel flow meters, the permittee may, with Division approval, satisfy the requirements of 40 CFR 60.4345(e) by implementing the QA program and plan described in section 1 of appendix B to 40 CFR 75. [40 CFR 60.4345(e)]

c. The permittee shall identify excess emissions using the following guidelines: [40 CFR 60.4350]

i. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h). [40 CFR 60.4350(a)]

ii. For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in appendix A of 40 CFR

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

iii. Correction of measured NO_X concentrations to 15 percent O_2 is not allowed. [40 CFR 60.4350(c)]

iv. If the permittee has installed and certified a NO_X diluent CEMS to meet the requirements of 40 CFR 75, the Division may approve that only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c). [40 CFR 60.4350(d)]

v. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. [40 CFR 60.4350(e)]

vi. Calculate the hourly average NO_X emission rates, in units of the emission standards under 40 CFR 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output-based standard: [40 CFR 60.4350(f)]

1. For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of 40 CFR 60, Subpart KKKK cited below, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations: [40 CFR 60.4350(f)(2)]

$$E=\frac{(NO_X)_h*(HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeters, e.g., calculated using Equation D-15a in appendix D to 40 CFR 75, and

P = gross energy output of the combustion turbine in MW

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

$$P = (PE)_t + (PE)_c + Ps + Po \quad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW

$(PE)_t$ = electrical or mechanical energy output of the CT in MW

$(PE)_c$ = electrical or mechanical output (if any) of the steam turbine in MW

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the system, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/hr,

H = enthalpy of steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and

3.413×10^6 = conversion from Btu/hr to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

d. The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The permittee must use one of the following sources of information to make the required demonstration: [40 CFR 60.4365]

   i. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. [40 CFR 60.4365(a)]
   ii. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu). At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.[40 CFR 60.4365(b)]

e. The permittee must monitor on a continuous basis the catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of 40 CFR 63, Subpart YYYY. [40 CFR 63.6125(a)]

   i. For a stationary combustion turbine that is required to comply with the emissions limitation for formaldehyde and is using an oxidation catalyst, the permittee must maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR 63.6125(a) and Table 2, Item 1 of 40 CFR 63, Subpart YYYY]

ii. Initial compliance is demonstrated if the average formaldehyde concentration meets the emission limitations specified in Table 1 of 40 CFR 63, Subpart YYYY. [40 CFR 63.6110, 63.6125, 63.6130, and Table 4 of 40 CFR 63, Subpart YYYY]

iii. Continuous compliance with the operating limit is demonstrated by continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer. [40 CFR 63.6135, 63.6140(a), and Table 5 of 40 CFR 63, Subpart YYYY]

iv. The permittee must report each instance in which they did not meet each emission limitation or operating limitation. The permittee must also report each instance in which they did not meet the requirements in Table 7 of 40 CFR 63, Subpart YYYY that apply to U23/49a. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in 40 CFR 63.6150. [40 CFR 63.6140(b)]

f. Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating. [40 CFR 63.6135(a)]

g. Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of 40 CFR 63, Subpart YYYY, including data averages and calculations. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine. [40 CFR 63.6135(b)]

h. The permittee shall measure CO and NO_X emissions using CEMS to demonstrate compliance with the applicable CO and NO_X emission limit under 401 KAR 51:017. The 30-day rolling averages will be calculated at the end of each unit operating day as the sum of CO mass (lbs) and the sum of NO_X mass (lbs) including non-operational hours divided by the sum of the heat input (MMBtu) for 30 consecutive unit operating days. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 2; 40 CFR 75, Appendix A; and 401 KAR 52:020, Section 10]

i. The permittee may use approved CEMS methodologies or other calculation methodologies of 40 CFR Part 75 Appendix G to demonstrate compliance with the applicable CO_2 emission limit under 401 KAR 51:017. The annual rolling average will be calculated at the end of each calendar month as the sum of monthly CO_2 mass (lbs) including non-operational periods divided by the sum of MWh-g for 12 consecutive months. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 3; 40 CFR 75, Appendix

A; 40 CFR 75, Appendix G; and 401 KAR 52:020, Section 10]

5. **Specific Recordkeeping Requirements:**

a. Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that includes written procedures for CMS according to 40 CFR 63.8(d)(1) through (2). The permittee must keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of 40 CFR Part 63, to be made available for inspection, upon request, by the Division. If the performance evaluation plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Division, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under 40 CFR 63.8(d)(2). [40 CFR 63.6125(e)]

b. The permittee must keep the records as described in 40 CFR 63.6155(a)(1) through (7). [40 CFR 63.6155(a)]

c. The permittee must keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies. [40 CFR 63.6155(c)]

d. Any records required to be maintained by 40 CFR Part 63 that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the Division or the EPA as part of an on-site compliance evaluation. [40 CFR 63.6155(d)]

e. The permittee shall maintain records of NO_X and CO_2 CEMS data to demonstrate compliance with the applicable limits under 401 KAR 51:017. If the permittee elects to demonstrate compliance with the applicable filterable $PM/PM_{10}/PM_{2.5}$ limit under 401 KAR 51:017 using CEMS, the permittee shall maintain records of filterable PM CEMS data to demonstrate compliance with the applicable limit under 401 KAR 51:017.

f. The permittee shall maintain records of the following [401 KAR 52:020, Section 10]:
   i. Monthly and 12-month rolling emissions of NO_X, CO, VOC and CO_2 in tons.
   ii. Gross electrical output on a monthly basis in MWh-g from each CT.
   iii. Daily ULSFO usage in each CT.

6. **Specific Reporting Requirements:**

a. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, the permittee must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. [40 CFR 60.4375(a)]

b. Each permittee required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts to 40 CFR Part 60) and-or summary report form to the Division semiannually, except when: more frequent reporting is specifically required by an applicable subpart to CFR Part 60; or the Division, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [40 CFR 60.4395 and 40 CFR 60.7(c)]

iv. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. [40 CFR 60.7(c)(1)]

v. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

vi. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

vii. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)(4)]

c. All reports required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period. [40 CFR 60.4395]

d. For turbines using continuous emission monitoring, periods of excess emissions and monitor downtime that must be reported are defined as follows: [40 CFR 60.4380(b)]

i. An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in 40 CFR 60.4320. For the purposes of 40 CFR 60, Subpart KKKK, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three-unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of 40 CFR 60, Subpart KKKK, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30-unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours. [40 CFR 60.4380(b)(1)]

ii. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the owner or operator will use this information for compliance purposes. [40 CFR 60.4380(b)(2)]

e. The permittee must submit all of the notifications in 40 CFR 63.7(b) Notification of Performance Testing and (c) Quality Assurance/Test Plan, 63.8(e) CMS Performance Evaluation (except for 40 CFR 63.8(e)(5)(ii), which applies to COMS), 63.8(f)(4) Alternative Monitoring, and 63.9(b) Initial Notifications and (h) Notice of Compliance Status that apply to the turbines by the dates specified. [40 CFR 60, Subpart A, 40 CFR 63.6145(a) and Table 7 of 40 CFR 63, Subpart YYYY]

f. If the permittee is required to submit an Initial Notification but is otherwise not affected by the emission limitation requirements of 40 CFR 63, Subpart YYYY, in accordance with 40 CFR 63.6090(b), the notification must include the information in 40 CFR 63.9(b)(2)(i) through (v) and a statement that the new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine). [40 CFR 63.6145(d)]

g. If the permittee is required to conduct an initial performance test, submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1). [40 CFR 63.6145(e)]

h. If the permittee is required to comply with the emission limitation for formaldehyde, the permittee must submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, the permittee must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test. [40 CFR 63.6145(f)]

i. **Compliance report.** The owner or operator of a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report and annual fuel oil hours report according to Table 6 of 40 CFR 63, Subpart YYYY. The semiannual compliance report must contain the information described in 40 CFR 63.6150(a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of 40 CFR 63.10(e)(3), must be submitted by the dates specified in 40 CFR 63.6150(b)(1) through (5), unless the Division has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, the permittee must submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g). [40 CFR 63.6150(a)]

    i. Company name and address. [40 CFR 63.6150(a)(1)]

    ii. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report. [40 CFR 63.6150(a)(2)]

    iii. Date of report and beginning and ending dates of the reporting period. [40 CFR 63.6150(a)(3)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

iv. Report each deviation in the semiannual compliance report. Report the information specified in 40 CFR 63.6150(a)(5)(i) through (iv). [40 CFR 60.4380(b)(5)]

1. Report the number of deviations. For each instance, report the start date, start time, duration, and cause of each deviation, and the corrective action taken. [40 CFR 60.4380(b)(5)(i)]

2. For each deviation, the report must include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions. [40 CFR 60.4380(b)(5)(ii)]

3. Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks), as applicable, and the corrective action taken. [40 CFR 60.4380(b)(5)(iii)]

4. Report the total operating time of the affected source during the reporting period. [40 CFR 60.4380(b)(5)(iv)]

j. The first semiannual compliance report must cover the period beginning on the compliance date specified in 40 CFR 63.6095 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date specified in 40 CFR 63.6095. [40 CFR 63.6150(b)(1)]

k. The first semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified in 40 CFR 63.6095 [40 CFR 63.6150(b)(2)]

l. Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. [40 CFR 63.6150(b)(3)]

m. Each subsequent semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. [40 CFR 63.6150(b)(4)]

n. For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in 40 CFR63.6150(b)(1) through (4). [40 CFR 63.6150(b)(5)]

o. ***Performance test report.*** Within 60 days after the date of completing each performance test required by 40 CFR 63, Subpart YYYY, the permittee must submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3). [40 CFR 63.6150(f)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

i. ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/)*. The the permittee data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. [40 CFR 63.6150(f)(1)]

ii. ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI. [40 CFR 63.6150(f)(2)]

iii. ***Confidential business information (CBI).*** If the permittee claims some of the information submitted under 40 CFR 63.6150(f)(1) is CBI, the permittee must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in 40 CFR 63.6150(f)(1). [40 CFR 63.6150(f)(3)]

7. Specific Control Equipment Operating Conditions:

a. The SCR and oxidation catalysts shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer’s specifications and standard operating practices [401 KAR 50:055 and 51:017].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

Emission Unit 21: **Emergency Diesel Generator**

Description:	TBD
Primary Fuel:	Diesel
Maximum Continuous Rating:	1.25 MW
Manufacture Date:	TBD
Construction Commenced:	TBD

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 to 60.4219, Tables 1 to 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 to 63.6675, Tables 1a to 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. EU21 does not have to meet the requirements of Subpart ZZZZ and of Subpart A of 40 CFR Part 63 except for the initial notification requirements of 40 CFR 63.6645(f). [40 CFR 63.6590(b)(1)]

   b. The permittee shall operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 and 60.4205 over the entire life of the engine. [40 CFR 60.4206]

   c. The permittee shall operate and maintain stationary CI ICE according to manufacturer's instructions, change only those emission-related settings that are permitted by the manufacturer; and meet the requirements of 40 CFR part 1068, as they apply. [40 CFR 60.4211(a)(1) through (3)]

   d. The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). [40 CFR 60.4211(c) and (g)]

   e. The permittee shall operate the engine according to the requirements of 40 CFR 60.4211(f)(1) through (3) to be considered an emergency stationary ICE. [40 CFR 60.4211(f)]

   f. The permittee shall use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted. [40 CFR 60.4207(b), 401 KAR 51:017]

   g. The permittee shall install a non-resettable hour meter prior to startup of the emergency engine [40 CFR 60.4209(a)]

   h. The permittee shall comply with the General Provisions in 40 CFR 60.1 through 60.10, 60.12 through 60.17, and 60.19. [40 CFR 60.4246(a)]
   i. The permittee shall utilize good combustion and operating practices to control emissions of CO_2e. [401 KAR 51:017]

2. **Emission Limitations:**
   a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Pollutant	Emission Limit
NO_X	4.65 g/hp-hr
CO	2.6 g/hp-hr
VOC	0.12 g/hp-hr
PM, PM_{10}, $PM_{2.5}$	0.15 g/hp-hr

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

CO_2e	163 lb/MMBtu

b. The permittee shall certify their stationary CI ICE to the certification emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105. [40 CFR 60.4205(b) and 60.4202(a)(2)]

Compliance Demonstration Method:
The permittee shall comply with the emission standards specified in 40 CFR 60.4205 (b) by purchasing an engine certified to the emission standards, as applicable, for the same model year and maximum engine power. In addition, the permittee shall meet one of the requirements specified in 40 CFR 60.4211(a)(1) through (3) or 40 CFR 60.4211(g). [40 CFR 60.4211(a), (c), and (g)]

If the engine is operated according to the manufacturer's emission-related written instructions, the permittee shall keep records of conducted maintenance to demonstrate compliance, but no performance testing is required. [40 CFR 60.4211(a)(1)]

If the certified stationary CI internal combustion engine is not operated and maintained according to the manufacturer's emission-related written instructions or if the permittee changes the manufacturer's emissions related settings, the permittee must comply with the requirements of 40 CFR 60.4211(g), including the development of a maintenance plan, maintaining records of maintenance, conducting an initial performance test, and conducting subsequent performance tests every 3 years [40 CFR 60.4211(g)(3)]

3. **Testing Requirements**:
Testing shall be conducted at such times as may be requested by the Cabinet [401 KAR 50:045, Section 4].

4. **Specific Monitoring Requirements**:
   a. The permittee shall monitor the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall monitor the hours of operation of the emergency generator [401 KAR 52:020, Section 10 and 40 CFR 60.4209(a)]

5. **Specific Recordkeeping Requirements**:
   a. The permittee shall maintain records of the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall maintain records of the hours of operation on a monthly basis. [401 KAR 52:020, Section 10]

   c. The permittee shall meet the following recordkeeping requirements. [40 CFR 60.4214]

      i. Keep records of the hours of operation of the engine in emergency and non-emergency operation if the engine is not certified to meet the non-emergency emissions standards. [40 CFR 60.4214(b)]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ii. If the emergency generator engine is equipped with a diesel particulate filter, keep records of any corrective action taken after the backpressure monitor has notified the permittee that the high backpressure limit of the engine is approached. [40 CFR 60.4214(c)]

6. **Specific Reporting Requirements:**
   See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

Permit Number: V-18-027

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 22: Diesel Fire Pump Engine

Description:	TBD
Primary Fuel:	Diesel
Maximum Continuous Rating:	310 hp
Manufacture Date:	TBD
Construction Commenced:	TBD

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 to 60.4219, Tables 1 to 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 to 63.6675, Tables 1a to 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. The permittee shall meet the requirements of 40 CFR Part 63 by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements apply for the engine under 40 CFR Part 63. [40 CFR 63.6590(c)(6)]

   b. The permittee shall operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 and 60.4205 over the entire life of the engine. [40 CFR 60.4206]

   c. The permittee shall operate and maintain stationary CI ICE according to manufacturer's instructions change only those emission-related settings that are permitted by the manufacturer; and meet the requirements of 40 CFR part 1068, as they apply.. [40 CFR 60.4211(a)(1)-(3)]

   d. The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(c), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211 (g). [40 CFR 60.4211(c) and (g)]

   e. The permittee shall operate the engine according to the requirements of 40 CFR 62.4211(f)(1) through (3) to be considered an emergency stationary ICE. [40 CFR 60.4211(f)]

   f. The permittee shall use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted. [40 CFR 60.4207(b), 401 KAR 51:017]

   g. The permittee shall install a non-resettable hour meter prior to startup of the emergency engine [40 CFR 60.4209(a)]

   h. The permittee shall comply with the General Provisions in 40 CFR 60.1 through 60.10,

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

60.12 through 60.17, and 60.19. [40 CFR 60.4246(a)]

a. The permittee shall utilize good combustion and operating practices to control emissions of CO_2e. [401 KAR 51:017]

2. **Emission Limitations:**
   a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Pollutant	Emission Limit
NO_X	2.76 g/hp-hr
CO	2.6 g/hp-hr
VOC	0.22 g/hp-hr
PM, PM_{10}, $PM_{2.5}$	0.15 g/hp-hr
CO_2e	163 lb/MMBtu

   b. The permittee shall comply with the emission standards in Table 4 of 40 CFR 60, Subpart IIII, for all pollutants. [40 CFR 60.4205(c)]

   Compliance Demonstration Method:
   The permittee shall comply with the emission standards specified in 40 CFR 60.4205 (c) by purchasing an engine certified to the emission standards, as applicable, for the same model year and maximum engine power. In addition, the permittee shall meet the requirements specified in 40 CFR 60.4211(a)(1) through (3), except as permitted under 40 CFR 60.4211(g). [40 CFR 60.4211(a), (c), and (g)]

   If the certified stationary CI internal combustion engine is not operated and maintained according to the manufacturer's emission-related written instructions or if the permittee changes the manufacturer's emissions related settings, the permittee must comply with the requirements of 40 CFR 60.4211(g), including the development of a maintenance plan, maintaining records of maintenance, conducting an initial performance test, and conducting subsequent performance tests every 3 years [40 CFR 60.4211(g)(3)]

3. **Testing Requirements:**
   Testing shall be conducted at such times as may be requested by the Cabinet [401 KAR 50:045, Section 4].

4. **Specific Monitoring Requirements:**
   a. The permittee shall monitor the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall monitor the hours of operation of the emergency fire pump [401 KAR 52:020, Section 10 and 40 CFR 60.4209(a)]

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall maintain records of the hours of operation on a monthly basis. [401

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

KAR 52:020, Section 10]

c. The permittee shall meet the following recordkeeping requirements. [40 CFR 60.4214]

iii. Keep records of the hours of operation of the engine in emergency and non-emergency operation if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year. [40 CFR 60.4214(b)]

d. If the diesel fire pump is equipped with a diesel particulate filter, keep records of any corrective action taken after the backpressure monitor has notified the permittee that the high backpressure limit of the engine is approached. [40 CFR 60.4214(c)]

6. Specific Recordkeeping Requirements:
See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 25: **CCGT Cooling Tower**

Description:
Maximum Continuous Rating: 165,800 gallons/minute (circulating water)
Control Device: Drift Eliminators
Drift Rate: 0.0005%
Construction Commenced: TBD

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 59:010, *New process operations*

NON-APPLICABLE REGULATIONS:
401 KAR 63:002, Section 2(4)(j), 40 C.F.R. 63.400 to 63.407, Table 1 (**Subpart Q**), *National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers*

1. **Operating Limitations:**
   a. The permittee shall minimize emissions of PM, PM_{10}, $PM_{2.5}$ through the use of inherent drift eliminators achieving 0.0005% drift loss. [401 KAR 51:017]

2. **Emission Limitations:**
   a. The permittee shall not emit any continuous emission into the open air from a control device or stack which is equal to or greater than 20 percent opacity. [401 KAR 59:010, Section 3(1)(a)]

   b. Particulate matter emissions shall not exceed the limit determined according to the following table, where P is the process weight rate in tons/hr and E is the maximum allowable emission rate in lbs/hr.

Process Weight Rate (tons/hr)	Emission Limit (lbs/hr)
$P \leq 0.5$	$E = 2.34$
$0.5 < P \leq 30$	$E = 3.59P^{0.62}$
$P > 30$	$E = 17.31P^{0.16}$

   [401 KAR 59:010, Section 3(2)]

   Compliance Demonstration Method:
   The permittee is assumed to be in compliance with the applicable opacity and particulate matter emission standard. [401 KAR 50:045, Section 4(3)(c)1.]

3. **Testing Requirements:**
   Testing shall be conducted at such times as may be requested by the Cabinet [401 KAR 50:045, Section 4].

4. **Specific Monitoring Requirements:**
   The permittee shall monitor total dissolved solids content of the circulating water on a monthly basis. [401 KAR 52:020, Section 10]

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the maximum pumping capacity and monthly records of the total dissolved solids content. [401 KAR 52:020, Section 10]

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall maintain records of the manufacturer's design of the drift eliminators. [401 KAR 52:020, Section 10]

6. Specific Reporting Requirements:
See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

7. Specific Control Equipment Operating Conditions:
See **Section E – Source Control Equipment Requirements.**

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 26A, 26B, 27, and 28: Storage Tanks

Emission Unit	Description	Construction Commenced	Maximum Capacity	Fuel
26A	Fuel Oil Storage Tank #1	TBD	1,658,213 gallon	No. 2 Fuel Oil
26B	Fuel Oil Storage Tank #2	TBD	1,658,213 gallon	No. 2 Fuel Oil
27	Emergency Generator Diesel Storage Tank	TBD	1,000 gallon	Diesel
28	Pump Diesel Storage Tank	TBD	350 gallon	Diesel

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Operating Limitations:**
   a. The permittee shall maintain the diesel storage tanks in good operating condition [401 KAR 51:017]

2. **Emission Limitations:**

   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   None

5. **Specific Recordkeeping Requirements:**
   None

6. **Specific Reporting Requirements:**
   None

7. **Specific Control Equipment Operating Conditions:**
   None

Permit Number: V-18-027

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 30 and 31: Circuit Breakers

Description:

Maximum Continuous Rating:	EU30 – Three (3) 20 kV Turbine Circuit Breakers EU31 – Twelve (12) 170 kV Switchyard/Station Circuit Breakers
Control Device:	N/A
Construction Commenced:	TBD

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Operating Limitations:**
   a. The permittee shall maintain the SF_6 leak rate from each circuit breaker at less than 0.5% of the total charge on an annual basis. [401 KAR 51:017]

   Compliance Demonstration Method:
   The permittee shall install a circuit breaker system with a leak detection system.

   No further limits, monitoring, recordkeeping, or reporting are required for the circuit breakers.

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   None

5. **Specific Recordkeeping Requirements:**
   None

6. **Specific Reporting Requirements:**
   None

7. **Specific Control Equipment Operating Conditions:**
   None

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 32: **CCGT Paved Roadways**

Description: Plant Paved Roadways used as Haul Roads
Control Device: Wet suppression as needed
Construction Commenced: TBD

APPLICABLE REGULATIONS:
401 KAR 63:010, *Fugitive emissions*
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Operating Limitations:**
   a. The permittee shall not cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following: [401 KAR 63:010, Section 3(1)]

      i. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land; [401 KAR 63:010, Section 3(1)(a)]

      ii. Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts; [401 KAR 63:010, Section 3(1)(b)]

      iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or similar operations. [401 KAR 63:010, Section 3(1)(c)]

      iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; [401 KAR 63:010, Section 3(1)(d)]

      v. The maintenance of paved roadways in a clean condition; [401 KAR 63:010, Section 3(1)(e)]

      vi. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water. [401 KAR 63:010, Section 3(1)(f)]

   b. The permittee shall implement a plant-wide speed limit, established such that roadway emissions from truck traffic are minimized. The permittee shall provide training and post signage to ensure the speed limit is observed. [401 KAR 51:017]

   Compliance Demonstration Method:
   Compliance shall be demonstrated according to **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

N/A

3. Specific Monitoring Requirements:

a. The permittee shall monitor actions taken to prevent the discharge of visible fugitive emissions beyond the property line, including the application of wet suppression. [401 KAR 52:020, Section 10, 401 KAR 63:010, Section 3(1)]

b. If fugitive dust emissions beyond the lot line of the property are observed, conduct Reference Method 22 (visual determination of fugitive emissions) observations per Appendix A of 40 CFR Part 60. In lieu of conducting US EPA Reference Method 22, immediately perform a corrective action which results in no visible fugitive dust emissions beyond the lot line of the property. [401, KAR 52:020, Section 10, 401 KAR 63.010, Section 3(2)]

4. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the actions taken to prevent the discharge of visible fugitive emissions beyond the property line on a monthly basis. [401 KAR 52:020, Section 10]

b. Maintain a log of the reasonable precautions taken to prevent particulate matter from becoming airborne on a daily basis. Notation of the operating status, down-time, or relevant weather conditions are acceptable for entry to the log. [401 KAR 52:020, Section 10, 401 KAR 63.010, Section 3(1)]

c. Maintain a log of any Reference Method 22 performed and field records identified in Reference Method 22 and any corrective action taken and the results. [401 KAR 52:020, Section 10, 401 KAR 63.010, Section 3(1)]

5. Specific Reporting Requirements:

See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

6. Specific Control Equipment Operating Conditions:

a. The permittee shall use best management practices (e.g. road paving, sweeping, wet suppression systems and good housekeeping practices, etc.) to minimize fugitive dust emissions due to road traffic for all new roads associated with the Cooper Project. [401 KAR 51:017]

b. See **Section E – Source Control Equipment Requirements**.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 33: **Natural Gas Pipeline Fugitives**

Description:

Control Device: N/A
Construction Commenced: TBD

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Emission Limitations:**
   a. The permittee shall not allow VOC emissions from the natural gas pipeline fugitives to exceed 0.42 tpy [401 KAR 51:017]
   b. The permittee shall not allow CO_2e emissions from the natural gas pipeline fugitives to exceed 919 tpy [401 KAR 51:017]

   Compliance Demonstration Method:
   The permittee shall conduct weekly auditory, visual, and olfactory inspections for the presence of natural gas, and promptly repair any detected leaks.

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   None

5. **Specific Recordkeeping Requirements:**
   None

6. **Specific Reporting Requirements:**
   None

7. **Specific Control Equipment Operating Conditions:**
   None

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 34: **H_2SO_4 Storage Tank**

Description:
Maximum Capacity: 3,000 gal
Control Device: N/A
Construction Commenced: TBD

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Operating Limitations:**
   a. The permittee shall maintain the storage tank in good operating condition [401 KAR 51:017]

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   None

5. **Specific Recordkeeping Requirements:**
   None

6. **Specific Reporting Requirements:**
   None

7. **Specific Control Equipment Operating Conditions:**
   None

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. Although these activities are designated as insignificant the permittee must comply with the applicable regulation. Process and emission control equipment at each insignificant activity subject to an opacity standard shall be inspected monthly and a qualitative visible emissions evaluation made. Results of the inspection, evaluation, and any corrective action shall be recorded in a log.

Description Generally Applicable Regulation

	Description:	**Generally Applicable Regulation:**
1.	Storage vessels containing petroleum or organic liquids with a capacity of less than 10,567 gallons, providing (a) the vapor pressure of the stored liquid is less than 1.5 psia at storage temperature, or (b) vessels greater than 580 gallons with stored liquids having greater than 1.5 psia vapor pressure are equipped with a permanent submerged fill pipe.	N/A
2.	Storage vessels containing inorganic aqueous liquids, except inorganic acids with boiling points below the maximum storage temperature at atmospheric pressure.	N/A
3.	#2 oil-fired space heaters or ovens rated at less than two million BTU per hour actual heat input, provided the maximum sulfur content is less than 0.5% by weight.	N/A
4.	Machining of metals, providing total solvent usage at the source for this activity does not exceed 60 gallons per month.	N/A
5.	Volatile organic compound and hazardous air pollutant storage containers, as follows: (a) Tanks, less than 1,000 gallons, and throughput less than 12,000 gallons per year; (b) Lubricating oils, hydraulic oils, machining oils, and machining fluids.	N/A
6.	Machining where an aqueous cutting coolant continuously floods machining interface.	N/A
7.	Degreasing operations, using less than 145 gallons per year.	N/A
8.	Maintenance equipment, not emitting HAPs: brazing, cutting torches, soldering, welding.	NA
9.	Underground conveyors.	401 KAR 63:010
10.	Coal bunker and coal scale exhausts.	401 KAR 63:010
11.	Blowdown (sight glass, boiler, compressor, pump, cooling tower).	N/A
12.	On-site fire and emergency response training.	

Permit Number: V-18-027

SECTION C - INSIGNIFICANT ACTIVITIES (CONTINUED)

13.	Grinding and machining operations vented through fabric filters, scrubbers, mist eliminators, or electrostatic precipitators (e.g., deburring, buffing, polishing, abrasive blasting, pneumatic conveying, woodworking).	401 KAR 63:010
14.	Vents from ash transport systems not operated at positive pressure.	N/A
15.	Wastewater treatment (for stream less than 1% oil and grease).	
16.	Sanitary sewage treatment.	N/A
17.	Heat exchanger cleaning and repair.	N/A
18.	Equipment used exclusively for forging, pressing, drawing, stamping, spinning, or extruding metals. This does not include emissions due to quenching activities.	N/A
19.	Repair and maintenance of ESP, fabric filters, etc.	N/A
20.	Ash handling, ash pond and ash pond maintenance	401 KAR 63:010
21.	Laboratory fume hoods and vents used exclusively for chemical or physical analysis, or for "bench scale production" R&D facilities	N/A
22.	Covered conveyors for coal or coke that convey less than 401 KAR 63:010 200 tons per day	401 KAR 63:010
23.	EU 05 & 09 - Fly ash loadout systems (Silos A, B & C) configured for either railcar or truck	401 KAR 63:010
24.	Wood Unloading Area	401 KAR 63:010
25.	Portable Backup Conveyer	401 KAR 63:010
26.	DusTreat CF9156 in 850 gallon tank	401 KAR 63:010
27.	DusTreat DC6109 in 300 gallon tote	401 KAR 63:010
28.	Powdered Activated Carbon (PAC) System (500 lb/hr max)	401 KAR 59:010
29.	19% Aqueous Ammonia Storage Tank	N/A

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Particulate, nitrogen oxides, sulfur dioxide, and visible (opacity) emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

3. Commencing upon the Commercial Operation Date of the Cooper Project, Cooper Project emissions from EU18, 19 and 02 combined are limited to 112.83 tpy SO_2 on a 12-month rolling total basis (calculated on a monthly basis), to preclude applicability of 401 KAR 51:017**,** *Prevention of significant deterioration of air quality* [To preclude 401 KAR 51:017].

   Compliance Demonstration Method:
   The permittee shall calculate monthly SO_2 emissions for Emission Units 02, 18, and 19 and maintain a 12-month rolling total of SO_2 emissions. Monthly SO_2 emissions shall be determined for Emission Unit 02 using SO_2 CEMS. Monthly SO_2 emissions shall be determined for Emission Units 18 and 19 using monthly heat input of natural gas and ULSFO and appropriate emission factors. Appropriate emission factors shall be sourced from either AP-42, manufacturer emissions data, or performance testing. The permittee shall maintain records of the monthly and 12-month rolling total combined SO_2 emissions from EUs 18, 19, and 02. The 12-month rolling total emissions shall be reported for each semiannual period in accordance with Section F – Monitoring, Recordkeeping, and Reporting Requirements, item 5.

4. Natural gas sulfur content will be specified by a purchase contract, tariff sheet, or by a pipeline transportation contract. ULSFO sulfur content will be specified by supplier certifications. Alternatively, sulfur content may be determined by representative fuel sampling data using the procedures in Appendix D to 40 CFR Part 75.

5. Definitions:

Commercial Operation Date refers to the date at which EU18, EU19 produce electricity for sale, or EU2 produces electricity for sale following the modification to add the capability to fire 100% NG or a combination of NG and coal.

Cooper Project refers to the project that consists of two separate projects: (1) the construction and operation of two NG- and FO-fired combustion turbines (EU18 and 19) and (2) the modification of Cooper Unit 2 (EU2) to add the capability to fire 100% NG or a combination of NG and coal. [Ancillary equipment supporting the Project is not included for the purposes of this definition as used in this permit.]

6. The following units comprise the "EKPC System" and are subject to System-Wide emission limits:

a. Unit 1 (124 MW)("Cooper 1") and Unit 2 (240 MW)("Cooper 2") located at the John

SECTION L – CROSS-STATE AIR POLLUTION RULE (CSAPR)

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions at this source, are identified in the following tables. These units are subject to the requirements for the CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program

Unit ID: EU 01, coal-fired EGU					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X				
NO_X	X				
Heat input	X				

Unit ID: EU 02, coal-fired EGU					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E

SECTION L – CROSS-STATE AIR POLLUTION RULE (CSAPR) (CONTINUED)

	(for NO_X monitoring)				
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: EU18 and EU19 (Units 3 and 4, non-peaking NG-fired combustion turbines with FO backup)					
Parameter	CEMS requirements pursuant to 40 CFR part 75, Subpart B (for SO_2 monitoring) and 40 CFR part 75, Subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil- fired units pursuant to 40 CFR part 75, Appendix D	Excepted monitoring system requirements for gas- and oil- fired peaking units pursuant to 40 CFR part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, Subpart E
SO_2		X			
NO_X	X				
Heat Input		X			

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30) (CSAPR NOx Annual Trading Program), 401 KAR 51:250 Section 3(25) through 401 KAR 51:250, Section 3(30) (CSAPR NOx Ozone Season Group 2 Trading Program), and 401 KAR 51:260 Section 3(25) through 401 KAR 51:260, Section 3(30) (CSAPR SO2 Group 1 Trading Program). The monitoring, recordkeeping, and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website: http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR 75, Subpart E and 40 CFR 75.66 and 401 KAR 51:240, Section 3(30) (CSAPR NO_x Annual Trading Program), 401 KAR 51:250, Section 3(30) (CSAPR NO_x Ozone Season Group 2 Trading Program), and/or 401 KAR 51:260, Section 3(30) (CSAPR SO_2