Initial 

STATE OF GEORGIA
COUNTY OF FULTON

AFFIDAVIT OF IN SUPPORT OF CLAIM THAT INFORMATION IS PROTECTED UNDER GEORGIA LAW FROM DISCLOSURE TO THE PUBLIC

PERSONALLY APPEARED before the undersigned officer, authorized to administer oaths, , Affiant who, first being duly sworn, testifies as follows:

1. My name is I am of the age of majority and am competent in all respects to give this Affidavit. My testimony herein is based on personal knowledge and upon documents maintained in the files of Georgia Power Company's ("Georgia Power" or "Company") Corporate Office.

2. Georgia Power Company is a corporation headquartered in Atlanta, Georgia and is authorized to transact business in the State of Georgia. I am the Air Manager for Georgia Power, with primary responsibility for managing permitting, reporting, compliance guidance, and strategy services for Georgia Power facilities and business units. In my role as Air Manager, I am authorized to provide this Affidavit on behalf of Georgia Power.

3. On 12/8/23, Georgia Power Company will submit a "Redacted Copy" and a "Protected Copy" to the Air Protection Branch of the Georgia Environmental Protection Division ("EPD") of a PSD permit application (referred to hereinafter as the "Submittal") associated with the construction of three simple-cycle combustion turbines ("CTs") and associated equipment at Georgia Power's Plant Yates. The Submittal will be provided in compliance with EPD's Procedures for Submitting Information Pursuant to a Claim that Information in the Submittal is Protected Under Georgia Law from Disclosure to the Public. I affirmatively declare that information contained in the Submittal to EPD is protected under the Georgia Open Records Act, O.C.G.A. § 50-18-70, *et seq.*, from disclosure to the public and that the Redacted Copy is submitted to EPD as is, and that the Protected Copy is submitted to EPD with the expectation and understanding that information contained therein is subject to the claim Georgia Power declares in this affidavit that such information is protected under Georgia law from disclosure to the public. Support for this declaration, including citation to the specific provisions of Georgia law, is included below.

4. The Georgia Open Records Act provides in pertinent part that –

(a) Public disclosure shall not be required for records that are:

(34) Any trade secrets obtained from a person or business entity that are required by law, regulation, bid, or request for proposal to be submitted to an agency. An entity submitting records containing trade secrets that wishes to keep such records confidential under this paragraph shall submit and attach to the records an affidavit affirmatively declaring that specific information in the records constitute trade secrets pursuant to Article 27 of Chapter 1 of Title 10.

O.C.G.A. § 50-18-72(a)(34).

Initial

5. The Georgia Trade Secrets Act, O.C.G.A. § 10-1-760, *et seq.*, provides that a

> (4) 'Trade secret' means information, without regard to form, including, but not limited to, technical or nontechnical data, a formula, a pattern, a compilation, a program, a device, a method, a technique, a drawing, a process, financial data, financial plans, product plans, or a list of actual or potential customers or suppliers which is not commonly known by or available to the public and which information:
>
> (A) Derives economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use; and
>
> (B) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.
>
> O.C.G.A. § 10-1-761(4).

6. The Submittal is required to be provided to EPD to comply with 391-3-1-.03(1) of the Georgia Rules for Air Quality Control.

7. On behalf of Georgia Power Company, I affirmatively declare that identifying information about the CTs contained in the Submittal constitutes a trade secret pursuant to the Georgia Trade Secrets Act as shown herein.

8. The Trade Secret is proprietary information because information that could identify the specific CTs to which the Submittal relates is not commonly known and is not readily ascertainable by reasonable means by persons outside the business of Georgia Power. The Trade Secret contains details about the CTs currently planned for construction by Georgia Power. This proprietary commercial information has not been made publicly available outside of Georgia Power and its public disclosure has the potential to disrupt ongoing negotiations with the potential vendor of the CTs. Georgia Power has made reasonable efforts over time to maintain the secrecy of this Trade Secret, which efforts include, but are not limited to, limiting and controlling employee access to such information and prohibiting public disclosure of such information. Georgia Power has previously protected this information under this same authority in its submittals to the Georgia Public Service Commission. Georgia Power submits this affidavit in furtherance of its ongoing and continual efforts to maintain the secrecy of the Trade Secret.

9. Under Georgia Code § 12-9-19 and Georgia Rule for Air Quality Control 391-3-1-.08, "reports on the nature and amounts of stationary source emissions obtained by the division shall be available for public inspection." The Trade Secret does not include any such reports and does not contain the kind of information that EPD procedures indicate cannot be claimed or treated as protected. All information necessary to determine the "nature and amounts" of emissions from the CTs is contained in Georgia Power's publicly available "Redacted Copy" of the Submittal. The "Protected Copy" of the Submittal contains additional information for use by EPD in verifying the origin or source of the data that is provided in the publicly available "Redacted Copy" of the Submittal.

Initial _____

10. Georgia Power Company understands that receipt by EPD of this Affidavit and the Submittal does not mean that EPD agrees or has made a determination that the information identified in this Affidavit is protected under the Georgia Open Records Act from disclosure to the public. However, for claims made in this Affidavit that information in the Submittal constitute a Trade Secret pursuant to the Georgia Trade Secrets Act, I understand that Section 50-18-72(a)(34) of the Georgia Open Records Act prescribes a procedure for producing such information in response to a request under that Act.

FURTHER Affiant saith not.

_____

Air Manager
Georgia Power Company
241 Ralph McGill Boulevard, N.E.

Atlanta, Georgia 30308-3374

Subscribed and sworn to before me this 4 day of December, 2023.

_____

[NAME of Notary Public]

My Commission expires: .....

EX... GEORGIA APRIL 26, 2026 PUBLIC COWETA COUNTY

App ID: 802465 Date Submitted: Dec 07, 2023

Current Status: Pending

Today is Dec 05, 2023

Georgia EPD Online System (GEOS) for Permitting, Compliance & Facility Information

Title V/SIP Application Redacted Information Report

Redacted Sequence	Form Section	Section ID	Field Name	Redacted Information

Attachment: PROTECTED COPY -- Plant Yates Units 8-10 PSD Application.pdf

Instructions:

Print or Download the "Redacted Information Report" and populate with the claimed protected information (in the "Redacted Information" column) or cite an Attachment name and **MAIL** it to the Division in Paper form according to the EPS's Procedures for Submitting Information Pursuant to a Claim that Information in the Submittal is Protected Under Georgia Law from Law from Disclosure to the Public.

1. The redacted Report can be downloaded and filled out and then PRINTED.
2. The Affidavit in Support of Claim[s] that Information is Protected under Georgia Law from Disclosure to the Public should be PRINTED.
3. The entire Public version of the application should be PRINTED. This can only be done AFTER it has been submitted. Open each form view in pdf and print.
4. Do not include electronic versions of the Redact Report or any Privileged information in the uploaded Attachments.
Please mail the report to:
Georgia Environment Protection Division
Air Protection Branch
4244 International Parkway Suite 120
Atlanta GA 30354

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

EXPEDITED PERMITTING PROGRAM – APPLICATION FOR ENTRY TO PROGRAM FOR AIR PERMITS

EPD Use Only

Date Received: _____ Application No. _____

To be eligible for expedited review, this application form must be accompanied by the complete permit application for the type of air permit being requested.

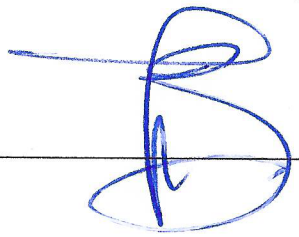
1. Contact Information

Facility Name: Yates Steam-Electric Generating Plant
AIRS No. (if known): 04-13-077-0001
Contact Person: _____ Title: Air Manager
Telephone No.: _____ Alternate Phone No.: _____
Email Address: _____ n

If EPD is unable to contact me, please contact the alternate contact person:
Contact Person: _____ Title: Senior Engineer
Telephone No.: _____ Alternate Phone No.: _____
Email Address: _____

On Page 2 of this form, please check the appropriate box for which type of air permit you are requesting expedited review.

I have read the Expedited Review Program Standard Operating Procedures and accept all of the terms and conditions within. I have participated in the required pre-application meeting with EPD. I understand that it is my responsibility to ensure an application of the highest quality is submitted and to address any requests for additional information by the deadline specified. I understand that submittal of this request form is not a guarantee that expedited review will be granted.

Signature:  Date: 12/7/2023

2. **Applying For Which Type Of Permit: (Please Check Appropriate Box)**

Expedited Review Fees for Air Permits	
Permit Type – Please Check One	**Expedited Review Fee* as of March 1, 2021**
☐ Generic Permit: Concrete Batch Plant – Minor Source	$1,250
☐ Generic Permit: Concrete Batch Plant – Synthetic Minor Source	$1,875
☐ Generic Permit: Hot Mix Asphalt Plant – Synthetic Minor Source	$2,500
☐ Minor Source Permit (or Amendment)	$3,750
☐ Synthetic Minor Permit (or Amendment)	$5,000
☐ Major Source SIP Permit not subject to PSD or 112(g)	$7,500
☐ Title V 502(b)(10) Permit Amendment	$5,000
☐ Title V Minor Modification with Construction	$5,000
☐ Title V Significant Modification	$7,500
☐ Major Source SIP Permit subject to 112(g) but not subject to PSD	$18,750
☐ PSD Permit (or Amendment) not subject to NAAQS and/or PSD Increment Modeling	$18,750
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling but not subject to Modeling for $PM_{2.5}$, NO_2, or SO_2	$25,000
☒ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2	$31,250
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2 and also impacting a Class I Area	$37,500
☐ Nonattainment NSR Review Permit (or Amendment)	$50,000
* Do not send fee payment with this form. Upon acceptance of application for the expedited permit program, EPD will notify you and an invoice will appear on GECO. Fees must be paid via check to "Georgia Department of Natural Resources" within ten (10) business days of acceptance.	

3. **Comments.**

GPC requests EPD to hold a public hearing in conjunction with issuance of the draft permit for the Project to ensure an opportunity for the public to participate.

This section is optional. Applicants may use this field to include specific comments or requests for EPD consideration. For example, the applicant may use this field to request a public hearing or to remind EPD of review time needs and/or expectations that may differ from the time frames in the procedures.

Georgia Power

Environmental &
Natural Resources
241 Ralph McGill Boulevard NE
Atlanta, GA 30308-3374

December 7, 2023

Georgia Environmental Protection Division
Air Protection Branch
Stationary Source Permitting Program
ATTN:
4244 International Parkway, Suite 120
Atlanta, Georgia 30354

Re: Yates Steam-Electric Generating Facility, Title V Permit No. 4911-077-0001-V-05-0
Proposed Combustion Turbine Units 8, 9, and 10 and Associated Equipment
f/k/a Project Peregrine
Request for Expedited Review of PSD Permit Application

Dear Mr. ,

On October 23, 2023, Georgia Power Company (GPC) filed with the Georgia Public Service Commission (PSC) an update to its integrated Resource Plan (IRP) to address Georgia's rapidly growing energy needs. Since filing the last IRP in 2022, Georgia's economy has continued to thrive, bringing rapid economic growth and an unprecedented increase in the demand for energy to the state. As part of ensuring that we can meet these energy needs, GPC is proposing to construct and operate three (3) advanced class, dual-fuel simple-cycle combustion turbines (CTs) at Plant Yates to provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized. The proposed CT units – Yates Units 8, 9, and 10 – will provide new dispatchable generation with the operational flexibility needed to complement non-generating battery storage resources, support the continued integration of intermittent renewable resources and fleet transition, and provide peaking power when needed.

As discussed during our pre-application meeting on November 1, 2023, Yates Units 8, 9, and 10 and associated equipment will be subject to Prevention of Significant Deterioration (PSD) permitting requirements for emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, sulfuric acid mist, and GHG. As such, GPC submits the enclosed application and supporting information which demonstrates that, with application of the Best Available Control Technology (BACT), the project (1) will not cause or contribute to a violation of any primary or secondary National Ambient Air Quality Standard (NAAQS) or Class I or II PSD increment, (2) will not impair visibility in any Class II area, (3) will not adversely impact any Air Quality Related Value (AQRV) in any Class I area, and (4) will not exceed any Acceptable Ambient Concentration (AAC) under the Toxic Impact Assessment Guideline developed by the Georgia Environmental Protection Division (EPD) to safeguard public health, safety and welfare.

GPC must act on an accelerated timeline to meet Georgia's energy needs. Yates Units 8, 9, and 10 are necessary to meet capacity needs projected to occur in Winter 2026/2027 and accordingly, GPC aims to bring two of the proposed CT units online by the end of 2026, with the third to follow in the second quarter of 2027. In order to meet these timelines, we request that EPD accept this application for expedited review and would appreciate EPD's efforts to issue a PSD permit by April 2024. To support your team's effort, GPC will provide EPD with a proposed draft permit revision to the Plant Yates Title V permit for consideration before the year's end.

As indicated in the affidavit accompanying the enclosed application, certain information in the application is protected under Georgia law from disclosure to the public. Per your request, we are providing five (5) hard copies of the application with this information redacted and one (1) hard copy that should be protected pursuant to the claims made in the affidavit. Additionally, we have enclosed a thumb drive that contains electronic files associated with the application, including the electronic attachments submitted along with the GEOS application to revise Plant Yates' Title V permit.

If you have any questions concerning the enclosed application, or if there is anything that we can do to support EPD's expedited review of the application, please do not hesitate to contact me at
or

Sincerely,



Air Manager

enc/

STF-PIA-10-9 Attachment

REDACTED COPY

AECOM

Yates Steam-Electric Generating Plant Combustion Turbine Units 8, 9, and 10

Prevention of Significant Deterioration Permit Application

Submitted to the Georgia Department of Natural Resources,
Environmental Protection Division

Redacted information contained in this Submittal is subject to the claim or claims by JONATHAN BANDZUL declared in the attached affidavit that such redacted information is protected under Georgia law from disclosure to the public.

Project number: 60715323

December 2023

Delivering a better world

Prepared for:

Georgia Power Company

Prepared by:

AECOM
250 Apollo Drive
Chelmsford, MA 01824
aecom.com

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DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

1. Introduction

On October 23, 2023, Georgia Power Company (GPC) filed with the Georgia Public Service Commission (PSC) an update to its integrated Resource Plan (IRP) to address Georgia's rapidly growing energy needs. Since filing the last IRP in 2022, Georgia's economy has continued to thrive, bringing rapid economic growth and an unprecedented increase in the demand for energy to the state. As part of ensuring that we can meet these energy needs, GPC is proposing to construct three (3) advanced class, dual-fuel REDACTED REDACTED REDACTED simple-cycle combustion turbine (CT) units at Plant Yates ("the Plant"), located in Coweta County, Georgia. Construction of the proposed CT units will include installation of new associated equipment, such as an emergency generator, an emergency fire water pump engine, and three fuel gas heaters. The proposed CT units, designated as Combustion Turbine Units 8, 9, and 10, along with all associated equipment, will be hereinafter referred to as the "Project" (f/k/a Project Peregrine). The proposed CT units will be capable of being fueled with either pipeline quality natural gas or ultra-low sulfur (i.e., 15 ppm) distillate oil. When natural gas is available, the proposed CT units will provide up to approximately REDACTED MW of capacity. If gas is unavailable, the proposed CT units will run on distillate oil and provide approximately REDACTED MW of capacity. Each proposed CT unit will be equipped with a dilution selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions.

Plant Yates is an existing "major source" of criteria air pollutants, and the Project constitutes a "major modification" under Prevention of Significant Deterioration (PSD) permitting requirements. As such, GPC is applying to the Georgia Environmental Protection Division (EPD) for an air permit authorizing construction and operation of the Project. The Project will be subject to PSD requirements for emissions of NO_X, particulate matter (PM), particulate matter (PM) less than 10 microns in diameter (PM_{10}), PM less than 2.5 microns in diameter ($PM_{2.5}$), CO, VOC, sulfuric acid mist (SAM, or H_2SO_4), and greenhouse gases (GHG).

This Introduction and the other components of this document constitute the application for an air permit authorizing construction and operation of the Project under Ga. Comp. R & Regs. Rule 391-3-1-.03. This application and supporting analyses address the applicable permitting requirements for the Project and demonstrate the Project will comply with all applicable state and federal air quality regulations.

1.1 Facility Description

Plant Yates is located at 708 Dyer Road, on approximately 2,400 acres on the east bank of the Chattahoochee River in Coweta County, Georgia, approximately eight miles northwest of the city of Newnan. Originally, seven coal-fired steam generating units were operated at Plant Yates. Units 1, 2, 3, 4, and 5 were retired in 2015 and Units 6 and 7 were converted from coal to natural gas in 2015 as part of GPC's compliance strategy for the Georgia Multipollutant Rule and federal Mercury and Air Toxics Standards (MATS).

A facility location map is provided in Figure 1-1 and Figure 1-2.

The geographical coordinates for the approximate center of Plant Yates are:

- Universal Transverse Mercator (UTM) Easting: 695,000 meters;
- Universal Transverse Mercator (UTM) Northing: 3,704,400 meters;
- UTM Zone: 16;
- North American Datum (NAD): 1983;
- Elevation Above Mean Sea Level (AMSL): Approximately 740 feet AMSL.

Existing emissions sources at Plant Yates include Units 6 and 7 (Emission Unit IDs SG06 and SG07) and a natural gas-fired water bath heater (Emission Unit ID WBH1). Existing emissions sources that are categorized

STF-PIA-10-9 Attachment

as Title V insignificant activities at Plant Yates include an emergency generator for each of Units 6 and 7, an emergency fire pump and air compressor for both Units 6 and 7, and an emergency generator at security. Units 6 and 7 are each capable of generating approximately 360 megawatts (MW) following the gas conversion.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Figure 1-1. Location of Plant Yates (Aerial)

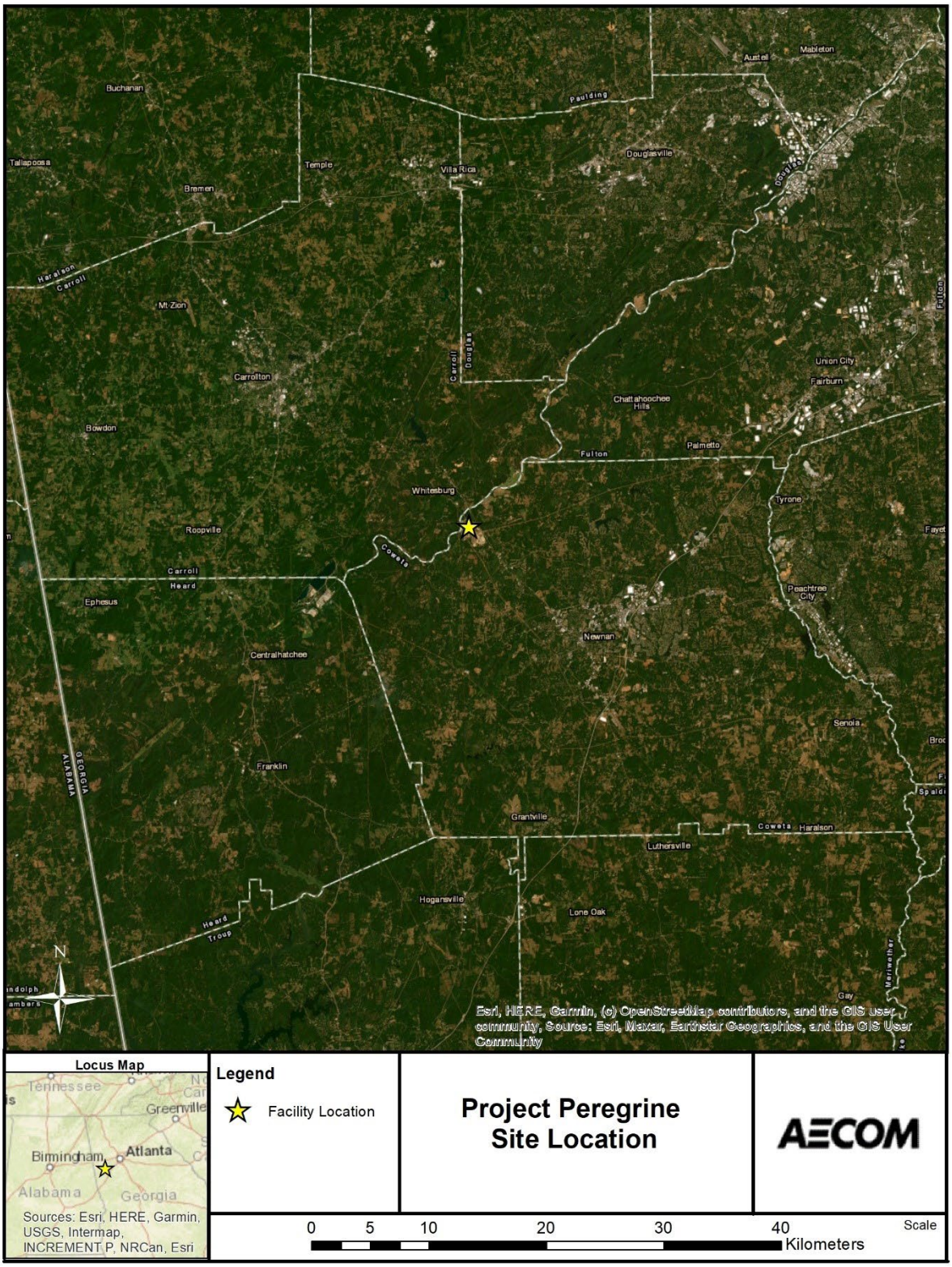


Figure 1-2. Location of Project (Aerial, zoom)



STF-PIA-10-9 Attachment

1.2 Project Description

GPC is proposing to construct Combustion Turbine Units 8, 9, and 10 (Emission Units IDs CT8, CT9, and CT10) to provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized. The proposed CT units are the primary sources of air emissions associated with the Project. The associated equipment proposed for the Project is listed below:

- One (1) ultra-low sulfur diesel (ULSD) fuel-fired emergency generator with an output capacity of 3250 kW,
- One (1) ULSD fuel-fired water pump engine with an output rating of approximately 350 bhp,
- One (1) ULSD fuel storage tank with a nominal capacity of 5.72 million gallons, and
- Three (3) natural gas-fired fuel gas heaters each with a heat input rating of less than 10 MMBtu/hr (Emission Units IDs WBH2, WBH3, and WBH4.

1.3 Project Location

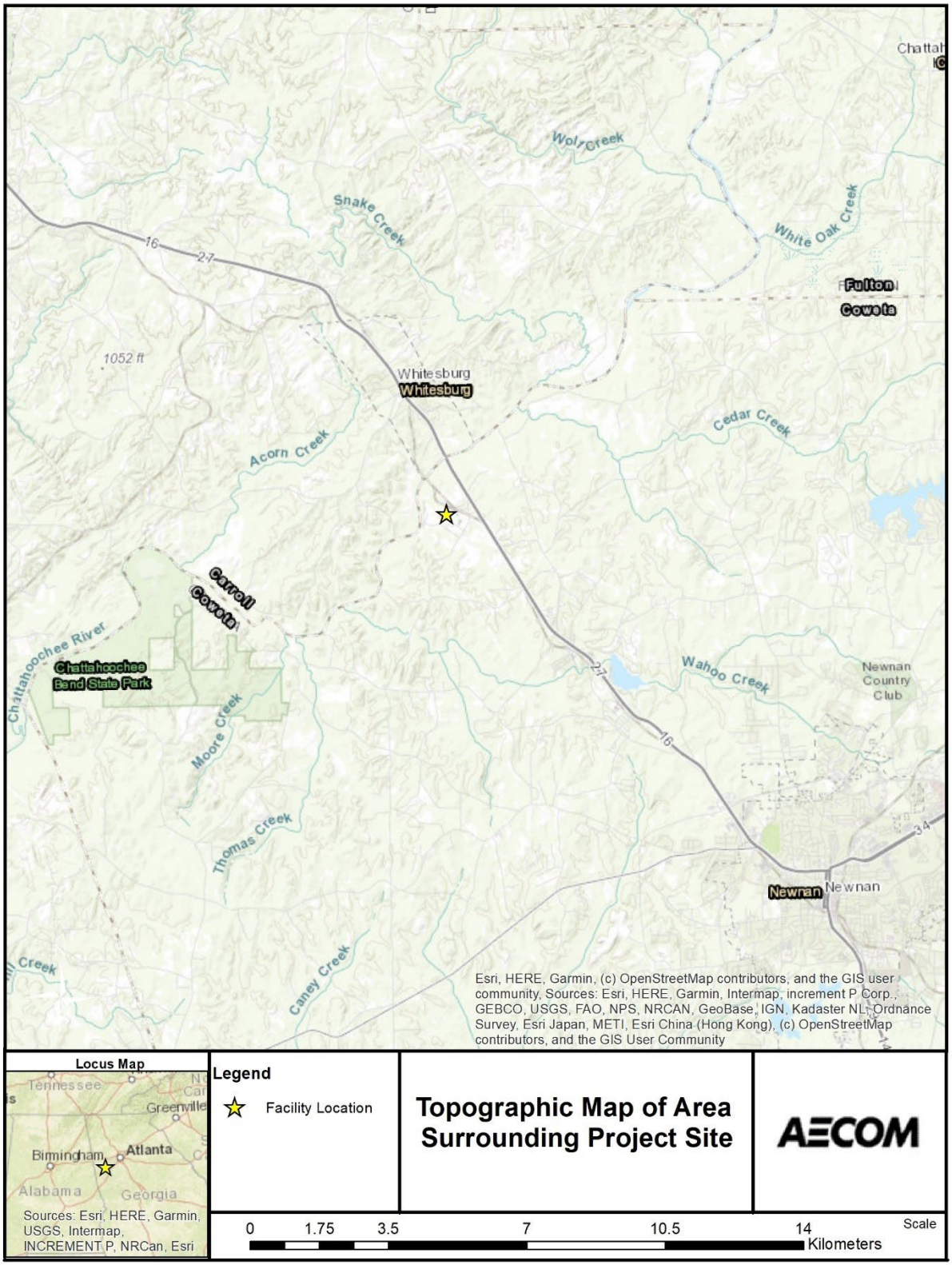
The proposed CT units and associated equipment will be located at Plant Yates, which is located in Coweta County on the Chattahoochee River, approximately 35 miles southwest of Atlanta, Georgia. Figure 1-1 and Figure 1-2 are aerial maps showing the location of Plant Yates and indicating the location of the Project. The land use surrounding the Project consists of a mix of mostly forested areas, water, and industrial areas. The topography surrounding Plant Yates, as indicated in the topographic map in Figure 1-3, is characterized by mostly flat areas with occasional gently rolling hills. A plot plan showing the Plant property, adjacent roadways, and source locations is presented in Appendix B.

1.4 Facility Classification

The facility is classified under the Standard Industrial Classification (SIC) code system as Electric Services, 4911, and classified under the North American Industrial Classification Systems (NAICS) as Fossil Fuel Electric Power Generation, 221112. Based on the facility's current and future potential to emit, Plant Yates is a "major stationary source."

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Figure 1-3. Location of Project (Topography)



1.5 Document Organization

The balance of this document is divided into sections which address each component of the PSD air quality review process. The outline below provides an overview of the contents of each of the remaining sections.

Section 2.0 – Process Description provides a general description of the primary process by which power will be produced at this site, as well as a description of the associated equipment.

Section 3.0 – Project Emissions Summary presents a detailed review of air emissions which will occur at the Project site due to the operation of the proposed CTs and associated equipment.

Section 4.0 – Requirements and Standards presents a discussion of potentially applicable State and Federal air regulations.

Section 5.0 - Control Technology Review presents the best available control technology determination for the pollutants for which PSD permitting is required, including a detailed evaluation of all potential control options for each pollutant.

Section 6.0 – Class II Area Air Quality Modeling Analysis Procedures summarizes the dispersion modeling methodology and manner in which the predicted impacts were compared to applicable standards. Specifically, this section discusses the modeling input data and the various modeling scenarios evaluated.

Section 7.0 – Class II Area Significant Impact Level (SIL) Analysis Results presents the results of the Class II Area SIL modeling results performed for the Project.

Section 8.0 – Class II Area Cumulative Impact Assessment Results presents the results of the Class II Area cumulative air dispersion modeling analysis performed for the Project. This section compares the modeled concentrations to the applicable standards.

Section 9.0 – Other Requirements Potentially Applicable to Air Permits Authorizing Construction contains supplemental information regarding the potential impacts of the Project. Specifically, this section discusses the potential for impacts to Class I areas and soils and vegetation.

Section 10.0 – Toxics Impact Assessment summarizes results of the air toxics analysis and modeling performed for the Project.

Section 11.0 - References include a list of the documents relied upon during the preparation of this document.

Appendices – Appendices A, B, C, D, E, and F provide permit application forms, plot plan, emission calculations, supporting BACT information, and Compliance Assurance Monitoring (CAM) forms. Additional information, figures and diagrams, dispersion modeling files, and supplemental materials supporting the information presented in the application are provided in Appendices G and H.

2. Process Description

As stated in Section 1, GPC plans to construct Combustion Turbine Units 8, 9, and 10 (Emission Units IDs CT8, CT9, and CT10) and associated equipment. The primary equipment of the Project includes:

- Three (3) REDACTED REDACTED REDACTED simple-cycle CTs, each with an ISO base rating of REDACTED MW (natural gas) and REDACTED MW (ultra-low sulfur distillate oil),

  REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED

Associated equipment associated with the Project includes:

- One (1) ULSD fuel-fired emergency generator with an output capacity of 3250 kW,
- One (1) ULSD fuel-fired water pump engine with an output rating of approximately 350 bhp,
- One (1) ULSD fuel storage tank with a nominal capacity of 5.72 million gallons, and
- Three (3) natural gas-fired fuel gas heaters each with a heat input rating of less than 10 MMBtu/hr.

2.1 Combustion Turbines

The proposed CT units will provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized. Annual operation of each proposed CT unit will be limited to a capacity factor based on its design efficiency for purposes of compliance with NSPS Subpart TTTT. Each proposed CT unit is comprised of three major sections: the compressor, the combustor, and the power turbine, as described below:

- In the compressor section, ambient air is drawn through a filter (and under certain meteorological conditions, the evaporative cooler) to clean (and cool) the air. The air is then compressed and directed to the combustor section.
- Each proposed CT unit will be capable of firing either natural gas or ultra-low sulfur distillate oil, hereinafter referred to as distillate oil or just oil. During natural gas firing, the proposed CT units will utilize dry low- NO_X ("DLN") combustors to reduce NO_X formation. During distillate oil firing, water injection will be used to minimize peak flame temperature and reduce NO_X formation.
- In the combustor section, a fuel and air mixture is introduced and combusted. Hot gases from combustion are mixed with additional air from the compressor section and directed to the power turbine section at high temperature and pressure.
- In the power turbine section, the hot exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

In addition to DLN and water injection, the emission control technologies for the proposed CT units include dilution selective catalytic reduction (SCR) to control NO_X emissions, as well as an oxidation catalyst to control CO, VOC, and organic HAP emissions.

2.2 Diesel-Fired Emergency Generator

The proposed Project will include one (1) ULSD-fired emergency generator with a standby rating of 3,250 kW certified to Tier 2 emission standards. The generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

STF-PIA-10-9 Attachment

2.3 Diesel-Fired Fire Water Pump Engine

The proposed Project will include one (1) ULSD-fired fire water pump engine rated at approximately 350 bhp certified to Tier 3 emission standards. The engine will be operated for emergency purposes for a maximum of 500 hours per year, including 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations.

2.4 Diesel Fuel Storage Tank

The Project will include a fixed roof storage tank with a nominal capacity of 5.72 million gallons for on-site storage of fuel for the proposed CT units to provide reliability and resiliency benefits to the electric system. The tank will be approximately 160' in diameter and equipped with a submerged fill system to reduce evaporative VOC emissions during filling operations.

2.5 Fuel Gas Heaters

The Project will include three (3) natural gas-fired fuel gas heaters, each with a heat input capacity of <10 MMBtu/hr, which will be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The heaters will fire natural gas exclusively and use ultra-low NO_X burners to control NO_X emissions.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

3. Project Emissions Summary

This section presents a summary of the Project emissions and a discussion of the methodologies used to calculate emissions. Within each emission source subsection below, the methods used to calculate emissions are discussed, followed by a summary of the emission estimates for each specific emission unit, and, for the proposed CT units, the mode of operation and fuel option. Section 3.1 below provides a summary of the potential hourly and annual emissions associated with the proposed Project for both fuel options.

The procedures used in determining the potential emissions from the Project are based on information provided by the turbine manufacturer, other equipment vendor data, emission limitations specified by the applicable New Source Performance Standards, emission factors documented in EPA's "Compilation of Air Pollution Emission Factors, AP-42," and proposed Best Available Control Technology (BACT) emission limits. Operational limitations (as appropriate) have been accounted for in estimating potential annual emissions.

Detailed emissions calculations for each emission source are presented in **Appendix C**.

3.1 Combustion Turbines

The main sources of emissions for the Project are the three proposed CT units. The following section presents the potential emission rates of these units. Additional emissions information at various loads, ambient temperatures, and operating conditions (e.g., evaporative cooling), as provided by the turbine manufacturer, are provided in **Appendix C** (Tables C-1 to C-4 and C-8 to C-9).

Annual operation of each proposed CT unit will be limited to a capacity factor based on its design efficiency for purposes of compliance with NSPS Subpart TTTT. The design efficiency of each proposed CT unit is approximately 41.5% based on an overall net efficiency on a lower heating value (LHV) basis of REDACTED Btu/kW at ISO conditions, which is equivalent to an annual heat input of 14,483,434 MMBtu on a higher heating value (HHV) basis.

Table 3-1 and **Table 3-2** present the maximum hourly emissions rate (lb/hr) and the maximum annual emissions (tons/year) during normal operations for each proposed CT unit for natural gas and distillate oil fuel combustion, respectively.

Table 3-1. Proposed CT Units: Hourly and Annual Emissions (Natural Gas/Normal Operations)

Pollutant	Maximum Hourly Emissions Rate Per CT during Normal Operations[1][2] (lb/hr/CT)	Potential Annual Emissions Rate Per CT during Normal Operations[1][3] (tons/year/CT)
NO_X	41.0	72.7
CO	35.0	63.6
VOC	11.4	20.4
TSP[4]	7.0	12.6
$PM_{10}/PM_{2.5}$	24.5	43.4
SO_2	5.7	10.2
H_2SO_4	8.8	15.5
Lead	0.002	0.004
GHGs (CO_2e)[5]	485,832	861,684

(1) See Appendix C for detailed calculations.
(2) Maximum hourly emissions (lbs per hr) are based on natural gas firing at 100% load at 20 degrees F.
(3) Annual emissions (tons per year) are based on a 41.5% capacity factor firing natural gas based on 100% normal full load at 59 degrees F without use of evaporative coolers (14,483,434 MMBtu).
(4) Total Suspended Particulate (TSP) is filterable PM emissions only. PM_{10} and $PM_{2.5}$ includes both filterable and condensable PM emissions.
(5) CO_2e is the equivalent number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-2. Proposed CT Units: Hourly and Annual Emissions (Distillate Oil/Normal Operations)

Pollutant	Maximum Hourly Emissions Rate Per CT during Normal Operations[1][2] (lb/hr/CT)	Potential Annual Emissions Rates Per CT during Normal Operations[1][3] (tons/year/CT)
NO_X	74.0	134.5
CO	45.0	81.8
VOC	10.3	18.7
TSP[4]	35.4	64.3
$PM_{10}/PM_{2.5}$	48.5	88.2
SO_2	5.3	9.6
H_2SO_4	8.1	14.7
Lead	0.048	0.088
GHGs (CO_2e)[5]	561,322	1,020,020

(6) See Appendix C for detailed calculations.
(7) Maximum hourly emissions (lbs per hr) are based on distillate oil firing at 100% load at 20 degrees F.
(8) Annual emissions (tons per year) are based on a 41.5% capacity factor firing distillate oil based on 100% normal full load at 59 degrees F without use of evaporative coolers (12,527,588 MMBtu).
(9) TSP is filterable PM emissions only. PM_{10} and $PM_{2.5}$ includes both filterable and condensable PM emissions.
(10) CO_2e is the equivalent number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-3 presents annual potential emission rates (tons/yr) of each regulated NSR pollutant for the proposed CT units. For each fuel, annual emission rates are presented for two scenarios: one that includes emissions during startup and shutdown, and one that does not. The maximum annual emission rate for each pollutant is highlighted in bold in **Table 3-3** below.

Table 3-3. Proposed CT Units: Annual Potential Emissions for Each Fuel

Pollutant	Potential Emission Rates (Three CTs)[1][2]				Potential to Emit (tpy)
	Natural Gas		Distillate Oil		
	Normal Operation (tpy)	With Startup and Shutdown (tpy)	Normal Operation (tpy)	With Startup and Shutdown (tpy)	
NO_x	218.1	293.0	403.5	**504.8**	504.8
CO	190.9	946.2	245.4	**3,013.8**	3,013.8
VOC	61.1	301.9	56.2	**1,041.2**	1,041.2
TSP	37.9	43.6	192.8	**251.0**	251.0
PM_{10} / $PM_{2.5}$	130.3	131.3	264.6	**316.4**	316.4
SO_2	**30.4**	29.6	28.8	27.4	30.4
H_2SO_4	**46.6**	45.4	44.0	42.0	46.6
Lead	0.01	0.01	**0.26**	0.25	0.26
GHG (CO_2e)	2,585,053	2,516,687	**3,060,060**	2,917,477	3,060,060

(1) See **Appendix C** for detailed calculations.
(2) See **Section 6.1.2** for detailed discussion of startup and shutdown emissions.

Table 3-4 presents the annual hazardous air pollutant (HAP) emission estimates for the proposed CT units for natural gas and distillate oil combustion. AP-42 emission factors were used to calculate the HAP emissions, except for formaldehyde, which was calculated based on the Combustion Turbine MACT (40 CFR 63 Subpart YYYY) emission limit of 91 ppbvd @ 15% O_2. Where AP-42 is used, no emission reduction for organic HAP is assumed for the oxidation catalyst. The emissions calculations assume a 41.5% capacity factor for operation on both fuels.

Table 3-4. Simple Cycle: Annual Potential Hazardous Air Pollutant (HAP) Emissions

Pollutant	Annual Potential HAP Emissions[(1)] Total for 3 CTs (tpy)	
	Natural Gas Combustion	Distillate Oil
Arsenic	4.26E-03	2.07E-01
Beryllium	2.56E-04	5.83E-03
Cadmium	2.35E-02	9.02E-02
Chromium (total)	2.98E-02	2.07E-01
Cobalt	1.79E-03	--
Lead	1.07E-02	2.63E-01
Manganese	8.10E-03	1.48E+01
Mercury	5.54E-03	2.25E-02
Nickel	4.48E-02	8.64E-02
Selenium	5.12E-04	4.70E+00
1,3-Butadiene	9.34E-03	--
Acetaldehyde	8.69E-01	--
Acrolein	1.39E-01	--
Benzene	2.61E-01	1.03E+00
Ethylbenzene	6.95E-01	8.45E-03
Formaldehyde	5.21E+00	4.89E+00
Naphthalene	2.82E-02	6.58E-01
Polycyclic Aromatic Hydrocarbons (PAHs)	4.78E-02	7.52E-01
Propylene Oxide	6.30E-01	--
Toluene	2.82E+00	8.24E-01
Xylene	1.39E+00	1.45E-02
TOTAL	**12.24**	**28.60**

(1) See Appendix C for detailed calculations.

3.2 Associated Equipment

The Project will include one ULSD-fired emergency generator and one ULSD-fired fire water pump engine which will be operated for emergency purposes, maintenance and readiness testing, and other allowed non-emergency situations. Three natural gas-fired fuel gas heaters will also be installed to warm the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. Emissions of criteria pollutants from the associated equipment are presented in **Table 3-5** and detailed emissions calculations are provided in **Appendix C** (Tables C-5 to C-7 and C-10 to C-13).

3.2.1 Emergency Engines

The Project will include one 3,250 kW emergency generator and a 350 bhp emergency fire water pump engine. The ULSD-fired emergency generator and fire water pump engine will meet the emission requirements in EPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII. The engines will also meet the applicable requirements of 40 CFR Part 63, Subpart ZZZZ.

The fire water pump engine and the emergency generator will operate for emergency purposes and for limited periods of routine testing, maintenance, and other non-emergency purposes. The fire water pump engine is considered an emergency engine and will be operated for no more than 500 hours per year, and the emergency generator will be operated for no more than 200 hours per year. Emissions of criteria pollutants and HAPs from the emergency engine are presented in **Table 3-5** and detailed emissions calculations can be found in **Appendix C** (Tables C-6, C-7, C-11, & C-12).

3.2.2 Diesel Fuel Storage Tank

One 5.72 million-gallon distillate oil fuel storage tank will be installed to provide fuel for the proposed CT units. VOC emissions from the storage tank will be minimized using submerged fill piping and a light-colored surface coating to reduce solar absorptance. Emissions of criteria pollutants from the fuel storage tank are also presented in **Table 3-5** and detailed emissions calculations are presented in Table C-13 of **Appendix C**.

3.2.3 Natural Gas-Fired Fuel Gas Heaters

The Project will also include three natural gas-fired fuel gas heaters, each with a heat input rating of 10 MMBtu/hr, to support the proposed CT units. Emissions of criteria pollutants from the natural gas-fired fuel gas heaters are also presented in **Table 3-5** and detailed emissions calculations are presented in Tables C-5 and C-10 of **Appendix C**.

Table 3-5. Annual Potential Criteria Pollutant and HAP Emissions from Associated Equipment

Pollutant	Potential Emergency Generator Emissions (tpy)	Potential Emergency Fire Water Pump Engine Emissions (tpy)	Potential Fuel Storage Tank Emissions (tpy)	Potential Fuel Gas Heaters Emissions (3 heaters) (tpy)
NOx	4.53	0.58	--	1.31
CO	0.54	0.50	--	9.72
VOC	0.23	0.58	3.11	1.31
TSP	0.12	0.029	--	0.98
PM_{10}	0.11	0.027	--	0.98
$PM_{2.5}$	0.10	0.026	--	0.98
SO_2	0.006	0.0011	--	0.18
Lead	3.8E-05	7.2E-06	--	6.4E-05
GHG (CO_2e)	447.3	84.7	--	15,387
HAPs	7.3E-03	2.6E-03	0.42	0.24

3.3 Total Annual Project Emissions

Table 3-6 provides the Project annual criteria pollutant potential to emit based on the maximum emitting scenario for the proposed CT units presented in **Table 3-3** and the potential to emit for associated equipment presented in **Table 3-5**. **Table 3-7** provides the annual HAP potential to emit.

As shown in **Table 3-6**, the Project triggers PSD review for several criteria pollutants. Total HAP potential to emit from the Project will exceed 25 tons/year, and individual HAP potential to emit will exceed 10 tons per year (see **Appendix C** for details).

Table 3-6. Total Project Potential to Emit of Criteria Pollutants (tpy)

Source	TSP(1)	PM_{10}(1)	$PM_{2.5}$(1)	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2e(2)
Simple-cycle CT (Unit 8)	83.7	105.5	105.5	168.3	1,004.6	347.1	10.1	15.5	8.77E-02	1,020,020
Simple-cycle CT (Unit 9)	83.7	105.5	105.5	168.3	1,004.6	347.1	10.1	15.5	8.77E-02	1,020,020
Simple-cycle CT (Unit 10)	83.7	105.5	105.5	168.3	1,004.6	347.1	10.1	15.5	8.77E-02	1,020,020
Emergency Generator	0.12	0.11	0.10	4.5	0.54	0.23	5.7E-03	--	3.8E-05	447
Fire Water Pump Engine	0.029	0.027	0.026	0.58	0.50	0.58	1.1E-03	--	7.3E-06	85
Diesel Fuel Storage Tank	--	--	--	--	--	3.1	--	--	--	--
Fuel Gas Heater (WBH2)	0.33	0.33	0.33	0.44	3.24	0.44	0.06	--	2.1E-05	5,129
Fuel Gas Heater (WBH3)	0.33	0.33	0.33	0.44	3.24	0.44	0.06	--	2.1E-05	5,129
Fuel Gas Heater (WBH4)	0.33	0.33	0.33	0.44	3.24	0.44	0.06	--	2.1E-05	5,129
Project Total	252	318	318	511	3,025	1,046	31	47	0.26	3,075,978
PSD Significance Level	25	15	10	40	100	40	40	7	0.6	75,000
PSD Review Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**

(1) TSP is filterable PM emissions only. PM_{10} and $PM_{2.5}$ includes both filterable and condensable PM emissions.
(2) CO_2e is the number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO_2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

Table 3-7. Annual Project Potential to Emit of HAP

Emission Source Description	HAP PTE (tpy)
Simple-cycle Units	28.60
Associated Equipment	0.67
Combined HAP	29.27
Largest Single HAP	14.85 (Manganese)

(1) See **Appendix C**, Tables C-8 to C-13 for detailed calculations based on AP-42 emission factors, except emissions of formaldehyde from the proposed CT units which are based on the CT MACT emission limitation of 91 ppbvd, corrected to 15% O_2. Additional information available to GPC demonstrates that Plant Yates is an area source of HAP emissions and will remain so after the Project. GPC intends to submit this information in a separate permit application.

4. Applicable Regulations

This section identifies the federal and state air quality regulations and standards that will govern construction and operation of the proposed Project. Specifically, the following regulations and standards were reviewed for applicability to the proposed Project:

- National Ambient Air Quality Standards (NAAQS)
- Prevention of Significant Deterioration (PSD) requirements
- Good Engineering Practice (GEP) Stack Height regulations
- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Compliance Assurance Monitoring (CAM) requirements
- Acid Rain Program (ARP)
- Risk Management Program (RMP)
- Cross-State Air Pollution Rule (CSAPR) requirements
- Greenhouse Gas Reporting Program (GHGRP)
- Georgia EPD regulations
- Georgia State Implementation Plan

The following subsections review the key elements of the identified regulatory programs and requirements and the impact of each on the permitting and operation of the proposed Project.

4.1 Ambient Air Quality Classification

The CAA authorizes EPA to establish National Ambient Air Quality Standards (NAAQS), and EPA has established a NAAQS for six air pollutants, which are presented in **Section 6**, **Table 6-1**. Newnan, Coweta County, Georgia, in which Plant Yates is located, is currently designated as attainment or unclassifiable for all of these NAAQS. See 40 CFR 81.311.

4.2 Prevention of Significant Deterioration (PSD) Program

4.2.1 PSD Applicability

Since Plant Yates is located in an area that has been designated as attainment or unclassifiable for all NAAQS, the Project must be evaluated to determine whether it constitutes a major modification at a major stationary source under PSD regulations. Plant Yates is a major stationary source because it is in one of the 28 major source categories listed in 40 CFR 52.21(b)(1)(iii) and referenced in Ga. Comp. R & Regs. 391-3-1-.02(7)(2) and has the potential to emit more than 100 tons per year of at least one regulated NSR pollutant. A major modification is defined as a physical change or change in the method of operation at a major source that results in a significant emissions increase and a significant net emissions increase in emissions that is greater than the PSD significant emission rates, as identified in **Table 4-1**.

Table 4-1. PSD Significant Emission Rates

Pollutant	Significant Emission Rate (tpy)
Carbon Monoxide (CO)	100
Nitrogen Oxides (NO_X)	40

Pollutant	Significant Emission Rate (tpy)
Sulfur Dioxide (SO_2)	40
Particulate Matter (PM)	25
Particulate Matter less than 10 microns in diameter (PM_{10})	15
Particulate Matter less than 2.5 microns in diameter ($PM_{2.5}$)	10 tpy of direct $PM_{2.5}$ emissions; or 40 tpy of SO_2 emissions; or 40 tpy of NO_X emissions unless demonstrated not to be a $PM_{2.5}$ precursor
Ozone (O_3)	40 tpy of volatile organic compounds (VOCs) or 40 tpy of NO_X
Lead (Pb)	0.6
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10
Greenhouse Gases (as CO_2e)	75,000

Source: Georgia Rules for Air Quality 391-3-1-.02(7) & GA EPD PSD Integrated Rule Document (2020)

The Project will result in emission increases greater than the above PSD significant levels for NO_X, PM, PM_{10}, $PM_{2.5}$, CO, VOC, H_2SO_4, and GHG as previously shown in **Table 3-6**. Therefore, PSD review is required for these pollutants.

4.2.2 PSD Program Requirements

The following sections provide a summary of the requirements for projects subject to PSD permitting.

4.2.2.1 Best Available Control Technology

Major sources conducting a major modification must meet the Best Available Control Technology (BACT) for all pollutants for which PSD permitting is required. Guidelines for the evaluation of BACT can be found in EPA's Draft New Source Review Workshop Manual (EPA 1990) and other guidance documents. EPA has also published guidance on BACT for greenhouse gas emissions.

The BACT analysis for the Project is presented in **Section 5**.

4.2.2.2 Ambient Air Quality Analysis Requirements

In accordance with the requirements of 40 CFR 52.21(m), a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants for which PSD permitting is required. The analysis of existing air quality can be based on air monitoring data from either a state-operated or private network, or a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source.

The requirements for the ambient air quality analysis are discussed in **Section 6.9**.

4.2.2.3 Source Impact Analysis

In accordance with the requirements of 40 CFR 52.21(k), a source impact analysis must be performed for a proposed project for each pollutant that triggers PSD review to demonstrate that the project will not cause or contribute to an exceedance of any NAAQS and PSD increments. This is first demonstrated by assessing project-modeled concentrations relative to Significant Impact Levels (SILs) as an initial screening step, assuming the use of the SILs can be justified for the proposed project. Justification for the use of the SILs for the proposed project is provided in **Section 7.2**. For those pollutants that have modeled concentrations greater than the SILs, a cumulative analysis including nearby background sources is required to demonstrate that the project will not cause or contribute to an exceedance of the NAAQS or PSD increments.

PSD regulations specify that new major sources or modifications to existing major sources may impact baseline air quality only by a defined amount known as a PSD increment. PSD increments have been established for PM_{10}, $PM_{2.5}$, SO_2, and NO_2 (see **Section 6**, **Table 6-1**). The increment is dependent on the classification of the area (Class I, Class II, or Class III) in which the action is to take place. Class I areas are federally protected areas and include specifically defined national parks, national forests, and wilderness areas. The remainder (and vast majority) of the country (including Coweta County) is designated as a Class II area. To date, no Class III areas have been designated.

The PSD regulations require the use of atmospheric dispersion modeling to perform source impact analyses, estimate baseline and future air quality levels, and compare the results to NAAQS and PSD increments. Designated EPA models are used to perform these air quality analyses. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (GAQM), 40 CFR Part 51, Appendix W. In most circumstances, the source impact analysis requirement may be satisfied by demonstrating that the impact from the Project will not result in an impact above the SILs presented in **Section 6**, **Table 6-1**.

Various periods of meteorological data can be utilized for an impact analysis. A minimum period of one year of onsite data or five years of representative meteorological data is typically required. The result of the source impact analysis is presented in **Sections 7** and **8**.

In addition to the source impact analysis, 40 CFR 52.21 of the PSD regulations requires applicants to conduct an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of construction and operation. The application must also address impacts due to commercial, residential, industrial, and other growth in the vicinity of the project to the extent this growth is a result of the project. These additional requirements are addressed in **Section 9** of this application.

4.3 Good Engineering Practice (GEP) Stack Height Analysis

The CAA requires that the degree of emission limitation required for control of any pollutant must not be affected by a stack which exceeds the GEP height (EPA 1985). This analysis is described in more detail in **Section 6.3**.

4.4 Applicability of New Source Performance Standards (NSPS)

The NSPS subparts potentially applicable to the Project include:

- Subpart A – General Provisions

- Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
- Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units
- Subpart TTTTa – Proposed Rule: Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units

An analysis of the applicability of each of these subparts is provided below.

4.4.1 Subpart A – General Provisions

All affected sources which are subject to a NSPS under 40 CFR Part 60 are subject to the general provisions of 40 CFR Part 60 Subpart A, unless those provisions are specifically excluded by an applicable source-specific NSPS. Since the Project will be subject to at least one NSPS, the permittee will be required to comply with applicable provisions of Subpart A. Subpart A contains initial notification, performance testing, monitoring, and recordkeeping requirements for the subparts, as applicable.

4.4.2 Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

As part of the proposed Project, the new facility will have storage tanks for the distillate oil that will be used in the proposed CT units, emergency generator, and fire water pump engine. 40 CFR Part 60, Subpart Kb regulates storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. However, Subpart Kb does not apply to storage vessels of any size storing a liquid with a maximum true vapor pressure less than 3.5 kPa (0.5 psia).

The maximum true vapor pressure of distillate oil stored at the Project will be less than 0.5 psia (~0.01 psia typ.). Therefore, the diesel fuel storage tanks at the facility will not be subject to this subpart.

EPA proposed NSPS Subpart Kc on October 4, 2023. If finalized as proposed, the diesel fuel storage tanks at the facility will not be subject to that subpart.

4.4.3 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The emergency generator and fire water pump engine are subject to the emission standards in 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. GPC will comply with the emission standards by purchasing an engine certified by the manufacturer to the emission standards in 40 CFR 60.4202, as applicable, for the same model year and maximum engine power. The emergency generator will be subject to Tier 2 standards and the fire water pump engine will be subject to Tier 3 standards under Subpart IIII and 40 CFR Part 1039. GPC will comply with all applicable Subpart IIII monitoring, recordkeeping, and reporting requirements. Since the engines will be designated and operated as emergency engines, they will only be operated in emergency circumstances and for a maximum of 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations.

4.4.4 Subpart KKKK – Stationary Combustion Turbines

The proposed CT units will be subject to 40 CFR Part 60, Subpart KKKK, which establishes NO_X and SO_2 emission limits for stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005 and have a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value.

4.4.4.1 Emission Limits for NO_X

Under Subpart KKKK, the proposed CT units are subject to NO_X emission standards of 15 ppm, corrected to 15% O_2, or 0.43 lb/MWh, when firing natural gas, and 42 ppm, corrected to 15% O_2, or 1.3 lb/MWh, when firing distillate oil, based on a 30-operating day rolling average.

As discussed in the BACT analysis in Section 5.0, the proposed CT units will reduce NO_X emissions using DLN, water injection, and SCR to comply with Subpart KKKK. Compliance with the Subpart KKKK emissions standards will be verified based on CEMS data.

4.4.4.2 Emission Limits for SO_2

The proposed CT units will be subject to either an emission limit of 0.9 lb/MWh gross output or a limit on the use of any fuel that contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input.

GPC will comply with the input-based emission standard for SO_2 by utilizing natural gas and distillate oil in the proposed CT units. Both fuels have a sulfur content lower than needed to meet the 0.06 lb SO_2/MMBtu limit.

4.4.5 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions from Electric Utility Generating Units

The proposed CT units will be subject to 40 CFR Part 60, Subpart TTTT, which applies to each electric utility generating units with a heat input greater than 250 MMBtu/hr of fossil fuel that serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction on or after January 8, 2014. GPC will comply with Subpart TTTT by limiting the capacity factor of each proposed CT unit to less than its design efficiency on a 12-operating month and 3-year rolling average basis and being permitted to burn only pipeline quality natural gas and distillate oil (see 40 CFR 60.5520(d)(1)).

4.4.6 Subpart TTTTa – Proposed Rule: Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units

EPA proposed 40 CFR Part 60, Subpart TTTTa on May 23, 2023. If this rule is promulgated as proposed, combustion turbines for which construction commences after the proposal date and that meet the relevant applicability criteria would be subject to the requirements of Subpart TTTTa rather than Subpart TTTT.

The proposed rule would be implemented in phases. For Phase I, the proposed emission standard for new intermediate load combustion turbines (less than 35-40 percent capacity factor, depending on efficiency level) is 1,150 lb CO_2/ MWhr gross and the proposed emission standard for low load or peaking combustion turbines (less than 20 percent capacity factor) is 120 – 160 lb CO_2/MMBtu of heat input, similar to the standard established under Subpart TTTT. For Phase II, intermediate load turbines would become subject to a more

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stringent emission standard of 1,000 lb/MWh based on the use of 30 percent low-greenhouse gas hydrogen, but low load or peaking units would remain subject to the Phase I standard.

EPA may finalize Subpart TTTTa as early as March 2024. GPC will evaluate the rule when it is finalized to determine how best to comply.

4.4.7 Non-Applicability of All Other NSPS

No other NSPS will apply to the emission units involved in the Project.

4.5 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP)

The proposed Project is not subject to any NESHAP under 40 CFR Part 61.

4.6 40 CFR Part 63 NESHAP

Plant Yates is currently classified as an existing major source of HAPs, and the emission units constructed as part of the Project will be subject to the provisions of several subparts of 40 CFR Part 63. However, additional information available to GPC demonstrates that Plant Yates is an area source of HAP emissions and will remain so after the Project. GPC intends to submit this information in a separate permit application.

Georgia EPD has incorporated these rules by reference under Ga. Comp. R & Regs. 391-3-1-.02(9). An analysis of the applicability of each of the potentially applicable subparts is provided below.

4.6.1 Subpart A – General Provisions

40 CFR Part 63 contains national emissions standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources which are subject to a NESHAP or MACT standard under 40 CFR Part 63 are subject to the general provisions of Subpart A unless those provisions are specifically excluded by an applicable source-specific NESHAP.

4.6.2 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The Industrial Boiler MACT (Subpart DDDDD) applies to boilers and process heaters constructed or reconstructed after June 4, 2010 and located at major sources of HAP.

“Process heaters” are defined in Subpart DDDDD as “…an enclosed device using controlled flame, and the unit’s primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials.” The proposed fuel gas heaters qualify as process heaters and will be subject to Subpart DDDDD.

The proposed fuel gas heaters are part of the designed to burn gas 1 fuels subcategory and have a heat input rating of less than 10 MMBtu/hr. Therefore, the proposed fuel gas heaters are not subject to the emission limits in Tables 1 and 2 or 11 through 13, or the operating limits in Table 4. However, the proposed fuel gas heaters are subject to the work practice standard outlined in Table 3, where it is required that a tune-up is

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

performed biennially (every two years) unless the unit has a continuous oxygen trim system at which point tune-ups can be conducted every five years.

4.6.3 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The Combustion Turbine MACT standard (Subpart YYYY) applies to stationary combustion turbines at major sources of HAP. The proposed CT units are subject to a formaldehyde emission limit of 91 ppbvd, corrected to 15% O_2, and other associated requirements, including an initial notification and testing.

4.6.4 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generator and fire water pump engine are subject to 40 CFR Part 63, Subpart ZZZZ and will comply with the applicable requirements of that subpart by complying with the applicable requirements in 40 CFR Part 60 Subpart IIII. No initial notification is required for the emergency engines per 40 CFR 60.4214(b) and 63.6590(c).

4.7 Acid Rain Program

The proposed CT units meet the definition of an affected Phase II “utility unit” under the Acid Rain Program (ARP) (40 CFR 72.6) because they are fossil fuel-fired combustion devices used to generate electricity for sale, and their capacity serves generators that exceed 25 MW. Plant Yates already has an existing Phase II Acid Rain Permit.

The primary applicable requirements under the ARP include:

- Amend the existing Phase II Acid Rain Permit for Plant Yates to include the new utility units;
- Install CEMS and fuel flow meters on the proposed CT units to demonstrate compliance with the requirements specified in 40 CFR Part 75; and
- Hold allowances equivalent to annual SO_2 emissions.

An Acid Rain permit application must be submitted 24 months before the units commence commercial operation and include the deadline for monitoring certification (90 days after commencement of commercial operation). The Acid Rain permit application is provided in Appendix A and is part of the electronic attachments to the GEOS application submitted for the Project.

GPC will operate in compliance with applicable provisions of the Title IV Acid Rain rules as adopted by reference under Ga. Comp. R & Regs. 391-3-1-.13. GPC will meet the applicable Acid Rain requirements that become effective after the issuance of the Acid Rain permit and will include the new units in its Title IV Acid Rain monitoring plan, as required under 40 CFR Part 72.

4.8 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) regulations are codified in 40 CFR Part 64 and Ga. Comp. R & Regs. 391-3-1-.02(11) by reference. The CAM Rule applies to pollutant-specific emissions units (PSEU) that:

1) are subject to an emission limit or standard, other than an emission limitation or standard:
    a) established after November 15, 1990 pursuant to section 111 or 112 of the Act;

b) establishing stratospheric ozone protection requirements under title VI of the Act;
c) establishing Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;
d) that applies solely under an emissions trading program approved by the Administrator under the Act;
e) for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1.

2) use a control device to achieve compliance with that emission limit or standard, and
3) have potential pre-control device emissions in the amount required to classify the unit as a major source under Part 70 of the Clean Air Act (CAA) (i.e., 100 tons/year).

The proposed CT units will be subject to CAM for the NO_X, CO, and VOC BACT emissions limits proposed as part of this application. The required CAM forms are provided in **Appendix D**.

For NO_X, GPC is proposing to monitor the concentrations of NO_X and O_2 using CEMS as CAM. This approach provides a direct measurement for the NO_X BACT emission limit. For CO and VOC, GPC is proposing to monitor the concentrations of CO and O_2 using CEMS with use of CO as a surrogate for VOC as CAM. This approach provides a direct measurement for the CO emission limit, as well as indirect assurance that VOC emissions are within their permitted limitation, since the generation and removal of these two pollutants are related.

4.9 Risk Management Program (RMP), Section 112(r)

Section 112(r) of the CAA mandates EPA to publish rules, which are codified in 40 CFR Part 68, requiring sources with more than the threshold quantity of a listed regulated substance to identify, prevent, and minimize the consequences of accidental releases. The three elements that must be incorporated into a source's RMP include:

- Hazard Assessment;
- Prevention Program; and
- Emergency Response Program.

The Project will store and utilize more than the threshold quantity of anhydrous ammonia in the SCR systems to control NO_X emissions from the proposed CT units; RMP requirements will thus apply to these systems.

4.10 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) requires states to address interstate transport of NO_X and SO_2 emissions that affect downwind states' ability to attain and maintain ozone and $PM_{2.5}$ NAAQS. CSAPR requirements include compliance with annual NO_X, seasonal NO_X (May through September), and SO_2 emission allowance programs and are codified at 40 CFR 97, Ga. Comp. R & Regs. 391-3-1-.02(12) through - Ga. Comp. R & Regs. 391-3-1-.02(14)

GPC will hold sufficient allowances to cover SO_2 and NO_X emissions and comply with the permitting, monitoring, recordkeeping, and reporting requirements set forth by CSAPR, including the installation and certification of CEMS and fuel flow meters.

4.11 Greenhouse Gas Reporting Program

The federal Greenhouse Gas Reporting Program (GHGRP), codified in 40 CFR Part 98, requires facilities belonging to certain source categories to report their annual GHG emissions to EPA. Affected source

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categories include electric generating units that report CO_2 mass emissions year-round through 40 CFR Part 75. Affected facilities must report their annual GHG emissions from the electric generating units and all other stationary fuel combustion sources (excluding emergency equipment) located at the facility. Thus, the proposed CT units and fuel gas heaters will be subject to 40 CFR Part 98 and GPC will report the annual GHG emissions from these emission units to EPA. However, the Greenhouse Gas Reporting Program does not constitute an "applicable requirement" under Title V.

4.12 Other Applicable Georgia Rules and Regulations

Georgia EPD has adopted or incorporated by reference many of the federal regulations described above into the State Implementation Plan (SIP) that has been approved by EPA. Other potentially applicable state regulations not previously mentioned are discussed below.

4.12.1 Ga. Comp. R & Regs. 391-3-1-.02(2)(b) – Visible Emissions

This regulation restricts visible emissions to no more than 40% opacity from "sources," which are defined to include stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys, or similar structures. The proposed CT units, gas heaters, emergency generator, and fire pump are subject to this regulation and will comply with the applicable requirements.

4.12.2 Ga. Comp. R & Regs. 391-3-1-.02(2)(d) – Fuel-Burning Equipment

This rule limits visible emissions, PM emissions, and NO_X emissions from fuel-burning equipment. The standards are based on installation date, heat input capacity of the unit, and fuel(s) combusted. As defined in 391-3-1-.01(cc), fuel burning equipment is:

> *"…equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for but not limited to, heating water, generating or super heating steam, heating air as in warm air furnaces, furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls."*

The proposed CT units will be used to generate electric power and will not be used for the production of thermal energy. As such, they do not meet the definition of fuel-burning equipment and are not subject to the requirements of this rule. However, the fuel gas heaters will be used for the production of thermal energy and will be subject to Rule (d).

4.12.3 Ga. Comp. R & Regs. 391-3-1-.02(2)(g) – Sulfur Dioxide

This rule limits the sulfur emissions from any fuel combusted in a fuel-burning source based on its heat input capacity. The emergency generator engine and firewater pump engines are not subject to this regulation because they do not produce thermal energy and thus do not meet the definition of fuel-burning equipment per 391-3-1-.01(cc). For fuel-burning sources such as the fuel gas heaters, the fuel sulfur content is limited to 3% sulfur by weight. The proposed CT units fit the definition of a fuel-burning source and are thus subject to this regulation. However, 40 CFR 60 Subpart KKKK contains a more stringent fuel sulfur limit. GPC will comply with Rule (g) by using pipeline quality natural gas and distillate oil in combustion.

4.12.4 Ga. Comp. R & Regs. 391-3-1-.02(2)(n) – Fugitive Dust

The fugitive dust rule applies to any operation, process, handling, transportation, or storage facility which has the potential to produce airborne dust. GPC will employ appropriate control methods and take precautions to limit fugitive dust emissions from the Project so as not to exceed 20% opacity.

4.12.5 Ga. Comp. R & Regs. 391-3-1-.02(2)(bb) – Petroleum Liquid Storage

Rule (bb) applies to fixed roof storage vessels with capacities exceeding 40,000 gallons which store petroleum liquids with true vapor pressure greater than 1.52 psia. While the proposed storage tank for the proposed CT units will have a capacity in excess of 40,000 gallons, the maximum true vapor pressure of distillate oil stored at the Project site will be less than 0.01 psia, so Rule (bb) will not apply.

4.12.6 Ga. Comp. R & Regs. 391-3-1-.02(2)(uu) – Visibility Protection

This rule applies to proposed major stationary sources or major modifications to an existing major stationary source that may have an impact on visibility in a Class I area. It requires EPD to provide an analysis of the proposed source's anticipated impact on visibility in any federal Class I areas to the appropriate Federal Land Manager (FLM). The visibility-impacting pollutants to be emitted from the proposed project include NO_X, PM_{10}, SO_2, and H_2SO_4. The nearest Class I area to Plant Yates is Cohutta Wilderness, which is approximately 150 kilometers north-northeast of the Project site. Based on the potential project emissions presented in Section 3, the Q/D value for this Class I area is less than 10, so a full review of the anticipated impact of the project on visibility at this area was not performed. Additional discussion on the visibility impact analysis for the Project is provided in **Section 9**.

4.12.7 Ga. Comp. R & Regs. 391-3-1-.02(2)(vv) – Volatile Organic Liquid Handling and Storage

Rule (vv) prohibits sources subject to other state VOC requirements located in specific counties in the state, including Coweta, from transferring volatile organic liquids into storage tanks greater than 4,000 gallons unless the tank is equipped with submerged fill pipes. No other state VOC requirements apply, so rule (vv) is not applicable. However, submerged filling is proposed as part of BACT for the storage tank for the proposed CT units.

4.12.8 Ga. Comp. R & Regs. 391-3-1-.02(2)(yy) – Nitrogen Oxides from Major Sources

Rule (yy) regulates the emissions of NO_X from facilities in the metro Atlanta area (including Coweta County). The rule requires facilities subject to the rule to demonstrate EPD approved Reasonably Achievable Control Technology (RACT) to control NOx emissions. Since Plant Yates is in Coweta County and emits more than the de minimums amount of NOx, rule (yy) applies. However, per Georgia Rule 391-3-1-.02 (2)(yy)5., the facility will comply with rule (yy) by complying with rules (mmm), (nnn), and (rrr).

4.12.9 Ga. Comp. R & Regs. 391-3-1-.02(2)(lll) – NO_X from Fuel-Burning Equipment

Rule (lll) sets NO_X limits for fuel-burning equipment with heat input capacities between 10 and 250 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. It applies between May 1 through September 30 of each year and provides that NO_X emissions must not exceed 30 ppm at 3% oxygen on a dry

basis. Plant Yates is located within the geographic area (Coweta County) covered by this rule. However, the proposed fuel gas heaters will each have heat inputs less than 10 MMBtu/hr and will therefore not be subject to this requirement.

4.12.10 Ga. Comp. R & Regs. 391-3-1-.02(2)(mmm) – NO_X Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity

Rule (mmm) establishes ozone season NO_X emission limits on stationary gas turbines and stationary engines with nameplate output capacities between 100 kWe and 25 MWe used for electricity generation and located in certain counties (including Coweta County). This rule is not applicable to either the emergency fire pump engine or the emergency generator. The rule will not apply to the proposed emergency fire pump engine because stationary engines not connected to an electrical generator are exempt from the standards. The emergency generator will also be exempt from the rule because it qualifies for an exemption for engines that operate "...only when electric power from the local utility is not available and which operate less than 200 hours per year are exempt from the NO_X emission limits under this rule."

4.12.11 Ga. Comp. R & Regs. 391-3-1-.02(2)(nnn) – NO_X Emissions from Large Stationary Gas Turbines

Rule (nnn) applies to stationary gas turbines with nameplate capacities greater than 25 MWe located in certain counties, including Coweta County. Under this rule, stationary gas turbines permitted after April 1, 2000 are subject to an ozone season NO_X emission limitation of 6 ppm @ 15% O2 on a dry basis. Compliance with this limitation is to be demonstrated on a 30-operating day rolling average. The proposed CT units will be subject to this limitation.

4.12.12 Ga. Comp. R & Regs. 391-3-1-.02(2)(rrr) – NO_X from Small Fuel-Burning Equipment

Rule (rrr) regulates the emissions of NO_X from small fuel burning units in the metro Atlanta area (including Coweta County). Rule (rrr) requires that small fuel burning equipment be fired only with natural gas, propane, or LPG, and requires a tune-up of equipment annually. This rule applies to individual fuel burning units with a maximum design heat input capacity of less than 10 MMBtu/hr and potential emissions of NO_X equal to or greater than one ton per year. As shown in Appendix C, Table C-5, the proposed fuel gas heaters will each have potential NO_X emissions less than one ton per year and thus will not be affected units under this rule.

4.12.13 Ga. Comp. R & Regs. 391-3-1-.03(1) – Construction (SIP) Permitting

SIP permitting requirements apply to facilities performing construction and modification activities that are not exempt under Ga. Comp. R & Regs. 391-3-1-.03(6). The Project will involve construction activities to install the proposed CT units, fuel gas heaters, emergency generator, and fire water pump. As discussed in Section 4.2, PSD permitting is required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in this application.

4.12.14 Ga. Comp. R & Regs. 391-3-1-.03(10) – Title V Operating Permits

Plant Yates is a Title V source and currently operates under Permit No. 4911-001-0001-V-05-0. It will remain a major source following completion of the project. This application requests a significant modification with

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construction (PSD) to Plant Yates' Title V permit and contains copies of the electronic attachments to the GEOS application submitted for the Project in Appendix A.

4.12.15 Non-Applicability of Other Georgia Air Quality Regulations

No other Georgia air quality rules are applicable to the Project.

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5. Control Technology Review

5.1 Technical Approach

5.1.1 Overview

Federal PSD regulations require a Best Available Control Technology (BACT) analysis for each new major source or major modification at an existing major source that will result in a significant net emissions increase of a NSR regulated pollutant. As described in Section 3 of this application, the potential emissions increases associated with the Project are sufficient to trigger PSD review for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, sulfuric acid mist, and GHG (as CO_2e).

Federal PSD regulations, as incorporated by reference in Georgia Rule 391-3-1-.02(7), define BACT as:

> *…an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such 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 such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR part 60, 61, or 63. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The BACT determinations summarized below are conducted in accordance with EPA guidance on BACT, including EPA's Guidance for Determining BACT Under PSD[1] and in the Draft New Source Review Workshop Manual,[2] as well as Georgia EPD's PSD Permit Application Guidance Document.[3]

5.1.2 BACT Assessment Methodology

The following sections describe the five steps of the top-down approach and provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the Project.

Step 1

The first step is to define the spectrum of process and/or add-on control options potentially applicable to the emissions unit and pollutant under review. There is no specific methodology that is required to be used to identify all available control options for a given source or pollutant. The most comprehensive source of this information, however, is EPA's RACT/BACT/LAER Clearinghouse (RBLC). This searchable database of

[1] Memo from David G. Hawkins, EPA Headquarters, on Guidance for Determining BACT under PSD to EPA Reg'l Adm'rs (Jan. 4, 1979).

[2] EPA, *Draft New Source Review Workshop Manual* (Oct. 1990).

[3] Georgia EPD PSD Permit Application Guidance Document (Posted February 3, 2017) (available at https://epd.georgia.gov/air-protection-branch-technical-guidance-0/types-air-quality-permits/prevention-significant).

emission control technology determinations is maintained by EPA, and as such, is generally the starting point for developing a list of potentially available control options.

Step 2

The second step is to evaluate the technical feasibility of the control options identified in the first step and to reject those that can be demonstrated as technically infeasible based on an engineering evaluation or on chemical or physical principles. In accordance with EPA's 1990 Workshop Manual, two key concepts are evaluated to determine whether an undemonstrated control option is technically feasible: "availability" and "applicability." A control option is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available control option is "applicable" if it can reasonably be installed and operated on the source type under consideration. A control option that is available and applicable is technically feasible. The following criteria are considered in determining technical feasibility: previous commercial-scale demonstrations, precedent based on issued PSD permits, state requirements for similar sources, technology transfer, and engineering evaluations for the control options or work practice standards considered.

Step 3

The third step involves ranking each technically feasible control option in decreasing order of overall control effectiveness considering specific operating constraints of the emission unit in question. After determining what control efficiency is achievable with each technically feasible control option, the alternatives are ranked into a hierarchy from most to least effective. Typically, the Step 3 ranking presents an array of control options, along with information such as control efficiencies (% pollutant removed or controlled), expected emission rate (tons/year, pounds/hour), expected emission reduction (tons/year), economic impacts (cost effectiveness), and adverse environmental and energy impacts. However, an applicant proposing the top control option as BACT need not provide cost and other detailed information regarding other control options.

Step 4

The fourth step consists of an objective evaluation of the energy, environmental, and economic impacts of each technically feasible control technology. The economic evaluation is carried out using procedures outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual.[4,5] The economic evaluation considers the annualized control cost (in dollars per ton of emissions removed) for the proposed source for each control option evaluated. If the top control option is determined to be cost ineffective or to cause adverse energy or environmental impacts, that control option is rejected and the analysis is performed on the next most stringent control option until the technology or emissions level under consideration cannot be eliminated based on source-specific environmental, energy, or economic impacts.

Step 5

The final step is to summarize the selection of BACT and emission limitations or work practices to be incorporated into the permit along with recommended monitoring and compliance demonstration requirements, including averaging times.

[4] EPA, *EPA Air Pollution Control Cost Manual*, at Sec. 1, Ch. 2 (7th ed. 2018).

[5] New and emerging technologies, such as CCS and co-firing low-GHG hydrogen, which are evaluated as part of the GHG BACT review for the proposed CT units, are generally not addressed in EPA's cost manual. Annualized costs for these control options were estimated using the publicly available references cited and adjusted to be consistent with the methodology in the manual.

5.2 Combustion Turbine BACT Review

5.2.1 Nitrogen Oxides

5.2.1.1 Formation

NO_X emissions from proposed CT units generally consist of two components: oxidation of atmospheric nitrogen in the combustion air (thermal NO_X and prompt NO_X) and conversion of fuel bound nitrogen (fuel NO_X). NO_X emissions mostly originate as nitric oxide (NO), which is generated by the combustion processes. NO emissions are subsequently further oxidized "in-stack" and in the atmosphere to the more stable NO_2 molecule.

Thermal NO_X results from the oxidation of atmospheric nitrogen during high temperature combustion and its formation is primarily a function of combustion temperature, residence time, and air/fuel ratio.

Prompt NO_X is formed near the combustion flame front in the oxidation of intermediate combustion products. Prompt NO_X comprises a small portion of total NO_X in conventional near stoichiometric combustors but increases during fuel-lean conditions. Prompt NO_X, therefore, is an important consideration with respect to low-NO_X combustors that use lean fuel mixtures. Prompt NO_X levels may also become significant with ultra-low-NO_X burners.

Fuel NO_X is due to the oxidation of non-elemental nitrogen contained in the fuel. Unlike thermal NO_X, fuel NO_X formation is less dependent on combustion variables such as temperature or residence time. Currently, there are no combustion controls or pre-combustion fuel treatment technologies available to reduce fuel NO_X emissions. For this reason, certain NO_X emissions standards contain an allowance for fuel-bound nitrogen as part of the emissions limit.[6]

NO_X emissions from combustion sources fired with distillate oil are typically higher than from those fired with natural gas due to higher combustion flame temperatures and fuel-bound nitrogen content. Natural gas may contain molecular nitrogen (N_2); however, the molecular nitrogen found in natural gas does not contribute significantly to fuel NO_X formation. Natural gas generally contains a negligible amount of fuel-bound nitrogen.

5.2.1.2 Step 1 – Identify NO_X Control Options

GPC searched EPA's control technology database, considered relevant existing and proposed federal and state emissions standards, reviewed recently issued new source review permits and associated applications, if available, for similar sources, and conducted interviews with original equipment manufacturer (OEMs) and owner/operators of similar large, advanced class dual-fuel simple-cycle CT units to identify potentially available control options for NO_X emissions from the proposed CT units. A search of the RBLC was conducted to identify NOx BACT determinations for large natural gas-fired and distillate oil-fired simple-cycle CT units (larger than 25 MW) permitted in the past ten years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix E**, Tables E-1 and E-2. Control technology determinations not included in the RBLC database include those made for Canal Generating Station Unit 3 in Massachusetts and for Lincoln Combustion Turbine Station Emission Unit 19 in North Carolina, which are the only similar large, advanced class dual-fuel simple-cycle CT units known to GPC to be in commercial operation in the US. Other similar CT units may be in commercial operation but operate in combined-cycle configurations.

Potentially available control options to reduce NO_X emissions from the proposed CT units include combustion controls, such as dry low-NO_X (DLN) combustors and water or steam injection, and post-combustion add-on controls, such as selective noncatalytic reduction (SNCR), nonselective catalytic reduction (NSCR), and selective catalytic reduction (SCR).[7] Each is discussed in the following sections.

[6] For example, see NSPS Subpart GG, 40 CFR 60.332(a)(1) through (4).
[7] GPC notes that multipollutant catalytic post-combustion add-on controls, such as EM_X™ (second-generation $SCONO_X$ absorber technology) and METEOR™ have been used to reduce emissions of NO_X, CO, and VOC from combined cycle

Water or Steam Injection

Water or steam injection was determined by EPA to be the best technology for control of NO_X emissions from stationary CT units when the national emissions standards for this source category were first established in 1977.[8] This control option involves the injection of water or steam into the combustor to decrease peak combustion temperature. The injected water or steam acts as a heat sink by diluting the combustion gas and absorbing heat needed to vaporize water. In doing so, peak flame temperature, combustion zone residence time, free oxygen, and thermal NO_X are reduced.

Dry Low NOx Combustors

Combustion controls that utilize combustor design and/or operational features to reduce NO_X emissions without injecting an inert diluent (water or steam) are generically referred to as "dry" low-NO_X (DLN) measures. Design features of DLN combustors are vendor-specific, but generally seek to reduce thermal NO_X formation by controlling peak combustion temperature, combustion zone residence time, and combustion zone free oxygen concentration. Designs include staged combustion and pre-mixing air and fuel prior to injection into the combustion zone. DLN measures produce a lean, pre-mixed flame that burns at a lower temperature with less excess oxygen than conventional combustors.[9]

Selective Noncatalytic Reduction

SNCR involves the gas phase reaction of NO_X in the exhaust gas stream with injected ammonia or urea, in the absence of a catalyst, to yield nitrogen and water vapor. Ammonia or urea is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}O_2 = 2N_2 + CO_2 + 2\ H2O \qquad (1)$$

$$4\ NH_3 + 6NO = 5N_2 + 6\ H2O \qquad (2)$$

Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls.[10] An important consideration for SNCR is operating temperature range. The temperature range required for this control option to be effective is approximately 1,600 to 2,000°F.[11] Operation at temperatures below this range results in ammonia slip. Operation at temperatures above this range results in oxidation of ammonia, forming additional NO_X emissions. Therefore, the SNCR injection system must be located such that operating temperatures are consistently within the identified range.

Nonselective Catalytic Reduction

NSCR uses a catalyst reaction to simultaneously reduce NO_X, CO, and VOC to water, carbon dioxide, and nitrogen without injection of a reagent such as ammonia. The conversion occurs in two sequential steps, with the reactions for CO and VOC occurring first since they more readily react with oxygen than with NO_X. However, to ensure NO_X reduction in the second step, this control option must be applied to exhaust gas streams with low oxygen content (less than 0.5% O_2).

Selective Catalytic Reduction

technology. However, according to combustion turbine OEMs, multipollutant catalysts are not technically feasible in simple-cycle CT applications. Separate catalysts are needed for adequate mixing of the dilution air with the exhaust gas to evenly distribute the temperature of the mixed gas across the SCR catalyst to optimize SCR effectiveness.

[8] 42 Fed. Reg. 53782, 53785 (Oct. 3, 1977).

[9] Currently, pre-mixing distillate oil and air is not an available control option. As such, water/steam injection is typically employed as a combustion control to control NO_X emissions during oil-firing.

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

[11] *Id.*

SCR is a post-combustion emission control process which involves removal of NOx in a catalytic reactor. In the SCR process, ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad (1)$$

$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \quad (2)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \quad (3)$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O \quad (4)$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O \quad (5)$$

A catalyst is required to lower the activation energy at which NOx decomposition occurs. Technical factors that must be considered with this control option include increased turbine backpressure, thermal considerations for structures and materials including shock/stress during startup, catalyst masking/blinding, reported catalyst failure due to “crumbling,” design of the ammonia injection system, and ammonia slip.

For most SCR catalyst configurations, the optimum operating temperature of the system is between 700 and 850°F. However, simple cycle CT units typically produce exhaust gas temperatures that exceed 1100°F. Consequently, this control option requires the use of high-temperature catalysts and the use of tempering air to reduce the temperature of the turbine exhaust prior to it being introduced into the SCR reactor. SCR catalyst materials lose activity over time, necessitating catalyst cleaning or replacement.

5.2.1.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Use of Water/Steam Injection and DLN Combustors

Use of DLN combustors and water injection is inherent to the Project and technically feasible.

Selective Non-catalytic Reduction

SNCR is not a technically feasible control option for NO_X emissions from the proposed CT units since it has not been demonstrated in practice and is not both an available *and* applicable control option. GPC is unaware of any case in which SNCR has been installed and operated successfully on the type of source under review; in the utility industry, this control option is typically applied to electric steam generating units (i.e., boilers). For utility boilers, ammonia is injected into the furnace where temperatures remain high enough for the NO_X reduction reaction to occur (between 1,600 and 2,000°F). The temperature of the exhaust gas from the proposed CT units is too low (between 1,100 and 1,200°F) for SNCR to be effective and it would not be practical or reasonable to further heat the exhaust gas so that this control option may be applied. Therefore, SNCR is not applicable to the proposed CT units. Accordingly, SNCR is not technically feasible.

Nonselective Catalytic Reduction

NSCR is also not a technically feasible control option for NO_X emissions from the proposed CT units since it has not been demonstrated in practice and is not both an available *and* applicable control option. GPC is unaware of any case in which NSCR has been installed and operated successfully on the type of source under review; this control option is most commonly applied to nonroad and stationary rich-burn spark-ignition internal combustion engines (SI ICE). For rich-burn SI ICE, air-to-fuel ratio controllers are used to maintain the low levels of excess oxygen necessary (less than 0.5%) for NSCR to be an effective control option for NO_X emissions. The oxygen content of the exhaust gas from proposed CT units will typically be 10-12%. Therefore, NSCR is not applicable to the proposed CT units. Accordingly, NCSR is not technically feasible.

Selective Catalytic Reduction

The use of SCR is included in the Project because it is necessary to comply with Georgia Rule (nnn), which is specific to the county (Coweta) in which GPC is proposing to construct and operate the proposed CT units. This emission standard will limit NO_X emissions from the proposed CT units to less than 6 ppmvd, corrected to 15% O_2, based on a 30-operating day rolling average. SCR will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. This control option has been demonstrated in practice for similar large, advanced class dual-fuel simple-cycle CT units such as Canal Generating Station Unit 3.

5.2.1.4 Step 3 – Rank Remaining NO_X Control Options

No ranking of control options is required as all available and technically feasible control options for NO_X emissions from the proposed CT units are included in the Project.

5.2.1.5 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for NO_X emissions from the proposed CT units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BACT determination for other sources or projects in areas not subject to Georgia Rule (nnn) or a similar standard that requires use of SCR.

5.2.1.6 Step 5 – Select NO_X BACT for Combustion Turbines

To comply with NSPS Subpart KKKK, the proposed CT units will be subject to a NO_X emission standard of 15 ppmvd while firing natural gas and 42 ppmvd while firing distillate oil.[12] These emissions standards serve as the BACT floor. However, as discussed above, the proposed CT units will also be subject Georgia Rule (nnn), which will limit NO_X emissions from the proposed CT units to less than 6 ppmvd, corrected to 15% O_2, based on a 30-operating day rolling average while firing either fuel.

NO_X BACT for the proposed CT units is based on use of clean fuels, DLN combustors, water injection, and SCR. Based on the RBLC search results, NO_X emission limits for simple-cycle CT units with similar controls range from 2.5 to 8.1 ppmvd while firing natural gas; there are two facilities with simple-cycle CT units with NO_X emission limits of 5.0 ppmvd while firing distillate oil. Canal Generating Station Unit 3, which is not included in EPA's RBLC database, is a similar large, advanced class dual-fuel simple-cycle CT unit with NO_X emission limits of 2.5 ppmvd and 5.0 ppmvd when firing natural gas and distillate oil, respectively, during normal operations (excluding startup and shutdown). Based on this information, GPC proposes the following as NO_X BACT for each of the proposed CT units:

- 2.5 ppmvd NO_X or less, corrected to 15% O_2, when firing natural gas based on a 4-hour rolling average (CEMS), excluding periods of startup, shutdown, or fuel switching,
- 5.0 ppmvd NO_X or less, corrected to 15% O_2, when firing distillate oil based on a 4-hour rolling average (CEMS), excluding periods of startup, shutdown, or fuel switching, and
- 168.3 tons NO_X or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

Startup means the period of time from when fuel is first fired to when the load has been achieved at which it has been demonstrated, by a CEMS or during compliance testing, that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 32 minutes for natural gas and 49 minutes for distillate oil.

[12] Except as otherwise noted, all numerical emissions standards and limits referred to in this BACT analysis in terms of parts per million by volume dry (ppmvd) are corrected to 15% O_2.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 5 minutes for natural gas and 15 minutes for distillate oil.

Fuel switching means the period of time needed to change fuels during load operation without a shutdown, not to exceed 20 minutes when switching from natural gas to distillate oil and 45 minutes when switching from distillate oil to natural gas.

In determining the 4-hour rolling average NO_X emissions rate, one-hour average emissions will be based on at least 30 minutes of normal operation (i.e., after startup and before shutdown) to ensure partial operating hours contain at least one valid measurement based on operation during a full quadrant of an hour. Rolling averages restart upon each startup.

5.2.2 Carbon Monoxide

5.2.2.1 Formation

CO emissions from the proposed CT units may be generated during combustion as a result of incomplete conversion of carbon-containing compounds to CO_2 and water. CO emission rates are principally influenced by equipment operating conditions; elevated CO emissions may be the result of low combustion temperature, insufficient combustor residence time, and/or low operating loads.

5.2.2.2 Step 1 – Identify CO Control Options

GPC searched EPA's control technology database, considered relevant existing and proposed federal and state emissions standards, reviewed recently issued new source review permits and associated applications, if available, for similar sources, and conducted interviews with original equipment manufacturer (OEMs) and owner/operators of advanced class dual-fuel simple-cycle CT units to identify potentially available control options for CO emissions from the proposed CT units. Like the NOx BACT review, a search of the RBLC was conducted to identify CO BACT determinations for large natural gas-fired and distillate oil-fired simple-cycle CT units (larger than 25 MW) permitted in the past ten years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix E**, Tables E-3 and E-4. Control technology determinations not included in the RBLC database include those made for Canal Generating Station Unit 3 in Massachusetts and for Lincoln Combustion Turbine Station Emission Unit 19 in North Carolina.

Potentially available control options to reduce CO emissions from the proposed CT units include combustion controls, good combustion practices, and post-combustion add-on controls such as an oxidation catalyst. Each are discussed in the following sections.

Combustion Controls and Good Operating Practices

As noted above, CO emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems (e.g., compressor inlet guide vane control) to achieve good combustion efficiency will minimize CO emissions from the proposed CT units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert CO emissions to CO_2 in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option include reactor design, operating temperature, back pressure of the system and its impact on performance, and catalyst life. Oxidation catalysts operate effectively in a relatively narrow temperature range typically between 600 to 800°F. As discussed above, simple-cycle CT units typically produce exhaust gas temperatures that exceed 1100°F. Consequently, the exhaust gas must be tempered with ambient air to avoid permanently damaging (sintering) the catalyst. At lower operating temperatures, CO conversion efficiency falls off rapidly.

5.2.2.3 Step 2 – Eliminate Technically Infeasible CO Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is included in the Project because it is necessary to comply with the CT MACT standards (40 CFR 63 Subpart YYYY). Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. This control option has also been demonstrated in practice by Canal Generating Station Unit 3.

5.2.2.4 Step 3 – Rank Remaining CO Control Options

No ranking of control options is required, as all available and technically feasible control options for NO_X emissions from the proposed CT units are included in the Project.

5.2.2.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for CO emissions from the proposed CT units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BACT determination for other sources or projects not subject to the CT MACT or a similar standard that requires use of oxidation catalyst.

5.2.2.6 Step 5 – Select CO BACT for Combustion Turbines

No BACT floor exists for CO emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

CO BACT for the proposed CT units is based on use of clean fuels, good combustion practices and oxidation catalyst. Based on the RBLC search results, CO emission limits for simple-cycle CT units with similar controls range from 5.0 to 30.7 ppmvd while firing natural gas; there is one facility with simple-cycle CT units with CO emission limits of 5.0 ppmvd while firing distillate oil. CO emissions from Canal Generating Station Unit 3 are limited to 3.5 ppmvd and 5.0 ppmvd when firing natural gas and distillate oil, respectively, while the CO emissions for Lincoln Combustion Turbine Station Emission Unit 19 are limited to 4.0 ppmvd while firing either fuel. Based on this information, GPC proposes the following as CO BACT for each of the proposed CT units:

- 3.5 ppmvd CO or less, corrected to 15% O_2, when firing natural gas based on a 4-hour rolling average (CEMS), excluding periods of startup, shutdown, or fuel switching,
- 5.0 ppmvd CO or less, corrected to 15% O_2, when firing distillate oil based on a 4-hour rolling average (CEMS), excluding periods of startup, shutdown, or fuel switching, and
- 1,004.6 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

Startup means the period of time from when fuel is first fired to when the load has been achieved at which it has been demonstrated, by a CEMS or during compliance testing, that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 32 minutes for natural gas and 49 minutes for distillate oil.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 5 minutes for natural gas and 15 minutes for distillate oil.

Fuel switching means the period of time needed to change fuels during load operation without a shutdown, not to exceed 20 minutes when switching from natural gas to distillate oil and 45 minutes when switching from distillate oil to natural gas.

In determining the 4-hour rolling average CO emissions rate, one-hour average emissions will be based on at least 30 minutes of normal operation (i.e., after startup and before shutdown) to ensure partial operating hours contain at least one valid measurement based on operation during a full quadrant of an hour. Rolling averages restart upon each startup

For distillate oil, GPC is not proposing the same level of control as Lincoln Combustion Turbine Station Emission Unit 19 since the 4.0 ppmvd emission limit is based on a much longer 24-hour average compared to the proposed 4-hour rolling average.

5.2.3 Volatile Organic Compounds

5.2.3.1 Formation

VOC emissions from the proposed CT units are influenced by the same factors that impact CO emissions discussed above.

5.2.3.2 Step 1 – Identify VOC Control Options

Potentially available control options for VOC emissions from the proposed CT units are the same as those discussed above for CO—combustion controls, good combustion practices, and post-combustion add-on controls, such as an oxidation catalyst. A search of the RBLC was conducted to identify VOC BACT determinations for large natural gas-fired and distillate oil-fired simple-cycle CT units (larger than 25 MW) permitted in the past ten years (i.e., since 2013). The results of these RBLC searches are summarized in **Appendix E**, Tables E-5 and E-6.

Combustion Controls and Good Operating Practices

Like CO, VOC emissions may result from incomplete combustion. Proper equipment design, proper operation, and optimization of the combustion air systems to achieve good combustion efficiency will minimize VOC emissions from the proposed CT units.

Oxidation Catalyst

An oxidation catalyst uses excess air to convert organic compounds to CO_2 in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option are the same as those discussed above for CO.

5.2.3.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Use of combustion controls and good operating practices is inherent to the Project and technically feasible.

The use of an oxidation catalyst is also included in the Project because it is necessary to comply with the CT MACT standards. Like the SCR, the oxidation catalyst will be made technically feasible by tempering the exhaust gas from the proposed CT units with ambient air to be within the temperature range necessary for this control option to be applicable. This control option has also been demonstrated in practice by Canal Generating Station Unit 3.

5.2.3.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required as all available and technically feasible control options for VOC emissions from the proposed CT units are included in the Project.

5.2.3.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for VOC emissions from the proposed CT units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required. However, consideration of those impacts could result in a different BACT determination for other sources or projects not subject to the CT MACT standards or a similar standard that requires use of an oxidation catalyst.

5.2.3.6 Step 5 – Select VOC BACT for Combustion Turbines

No BACT floor exists for VOC emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

VOC BACT for the proposed CT units is based on use of clean fuels, good combustion practices, and an oxidation catalyst. Based on the RBLC search results, VOC emission limits for simple-cycle CT units with similar controls are 2.0 ppmvd when firing natural gas and 4.5 ppmvd when firing distillate oil.[13] VOC emissions from both Canal Generating Station Unit 3 and Lincoln Combustion Turbine Station Emission Unit 19 are limited to 2.0 ppmvd while firing either fuel. Based on this information, GPC proposes the following as VOC BACT for each of the proposed CT units:

- 2.0 ppmvd VOC or less, corrected to 15% O_2, when firing either natural gas or distillate oil, based on the average of a 3-run stack test using EPA Reference Method 25A.

GPC proposes to conduct a stack test after initial startup followed by subsequent stack tests every five years. Like EPD's rationale in the VOC LAER determination for the combined-cycle units at Plant McDonogh, compliance with the VOC BACT emission limits for the proposed CT units will be assured as long as the CO emissions are in compliance with the corresponding CO BACT emission limits.

5.2.4 Particulate Matter

5.2.4.1 Formation

PM emissions from the proposed CT units include both filterable and condensable particles.[14] Filterable PM is formed from impurities contained in fuels, dust in the ambient air, and from incomplete combustion, while condensable PM is primarily attributable to high molecular weight VOC (unburned hydrocarbons) and the conversion of fuel sulfur to sulfates when catalyst-based add-on controls are used.

5.2.4.2 Step 1 – Identify PM Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potentially available control options for PM emissions from the proposed CT units. The results of these RBLC searches are summarized in **Appendix E**, Tables E-7 through E-12. Control technology determinations not included in the RBLC database include those made for Canal Generating Station Unit 3 in Massachusetts and for Lincoln Combustion Turbine Station Emission Unit 19 in North Carolina. Based on this review, no add-on control options were identified. Instead, many facilities listed

[13] In the RBLC search results, there are three facilities with natural gas-fired simple-cycle CT units with VOC emission limits of 1.4 ppmvd. The Shawnee Energy Center (TX-0768) and Tenaska Roans Prairie Generating Station (TX-0696) were planned facilities in Texas which were never constructed. The third facility is the Emporia Energy Center (KS-0036) in Kansas. Other information suggests that the VOC limit for the simple-cycle CT units at this facility is 0.0018 lb/MMBtu (see Table 5-17 in the Washington County Power, LLC application, TV-547905, dated February 25, 2021). If VOC is measured "as carbon", 0.0018 lb/MMBtu is equivalent to 2 ppmvd, corrected to 15% O_2. However, GPC could not independently confirm the basis for the VOC measurement for Emporia since the 2007 application materials and compliance stack tests are not readily available.

[14] For the purposes of BACT, emission limits for PM include only filterable PM, while emission limits for PM_{10} and $PM_{2.5}$ are required to include both filterable and condensable fractions. In this BACT analysis, when GPC uses the term "PM," it is meant to include both PM_{10} and $PM_{2.5}$ unless otherwise noted.

some variation of use of clean fuels (which inherently have low sulfur content) and good combustion practices as BACT. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired combustion turbines because the use of clean fuels inherently results in a low level of PM emissions.[15] Accordingly, only the use of cleans fuels and good combustion practices are considered further.

5.2.4.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Use of clean fuels (with inherently low sulfur content) and good combustion practices are inherent to the Project and technically feasible.

5.2.4.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as use of clean fuels and good combustion practices are the only available and technically feasible control options for PM emissions from the proposed CT units.

5.2.4.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed CT units. Therefore, no further evaluation of the impacts of the PM control options is required.

5.2.4.6 Step 5 – Select PM BACT for Combustion Turbines

Like CO and VOC, no BACT floor exists for PM emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

PM BACT for the proposed CT units is based on use of clean fuels with inherently low sulfur content and good combustion practices. Based on the RBLC search results, total PM emission limits for simple-cycle CT units with similar controls range from 0.006 to 0.015 lb/MMBtu when firing natural gas and from 0.007 to 0.025 lb/MMBtu ppmvd when firing distillate oil. Total PM emissions from Canal Generating Station Unit 3 when firing natural gas are limited to either 0.0073 lb/MMBtu or 0.0012 lb/MMBtu, depending on load, and to either 0.026 lb/MMBtu or 0.046 lb/MMBtu, depending on load, when firing distillate oil. Total PM emission limits for Lincoln Combustion Turbine Station Emission Unit 19 range from 0.004 to 0.009 lb/MMBtu when firing natural gas and from 0.006 to 0.0125 when firing distillate. Based on this information, GPC proposes the following as PM BACT for each of the proposed CT units:

- Total PM, containing filterable and condensable PM, equal to or less than 0.006 lb/MMBtu, or 24.5 lb/hr, when firing natural gas, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202 (this emission limit is comprised of approximately 0.002 lb/MMBtu filterable PM, 0.003 lb/MMBtu sulfate-based condensable PM, and 0.001 lb/MMBtu of carbon-based condensable PM); and
- Total PM, containing filterable and condensable PM, equal to or less than 0.014 lb/MMBtu, or 48.5 lb/hr, when firing distillate oil, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202 (this emission limit is comprised of approximately 0.010 lb/MMBtu filterable PM,

[15] When EPA originally proposed national standards for CT units in NSPS Subpart GG, EPA stated that "particulate emissions from stationary gas turbines are minimal" and noted that add-on controls for PM are not typically installed on CT units and are cost prohibitive. See 44 Fed. Reg. 52792, 52798 (Sept. 10, 1979); EPA, *Standards Support and Envtl. Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines*, at 8-6 (Sept. 1977). Additionally, when EPA proposed to update the standards in NSPS Subpart KKKK, EPA declined to establish standards for PM because "…[PM] emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the lower ash content…" 70 Fed. Reg. 8314, 8321 (Feb. 18, 2005). At the time, EPA also noted that no CT units permitted since 2003 utilized add-on controls.

STF-PIA-10-9 Attachment

0.003 lb/MMBtu sulfate-based condensable PM, and 0.001 lb/MMBtu of carbon-based condensable PM)

Since the PM BACT is based on use of clean fuels with inherently low sulfur content, GPC proposes to conduct a one-time stack test after initial startup to confirm emission performance.

5.2.5 Sulfuric Acid Mist

5.2.5.1 Formation

Sulfuric acid mist (SAM), or H_2SO_4, emissions from the proposed CT units occur as a result of oxidation of SO_2 to SO_3 as high temperature exhaust gas passes across the surfaces of the SCR and oxidation catalyst. The SO_3 then hydrates to form H_2SO_4 in the presence of water vapor.

5.2.5.2 Step 1 – Identify SAM Control Options

The only potentially available control option for SAM emissions from the proposed CT units is use of clean fuels with inherently low sulfur content. Conventional add-on controls for SAM often applied to solid fuel boilers, such as such as baghouses with sorbent injection and scrubbers, have never been applied to gas-fired combustion turbines because the use of clean fuels inherently results in a low level of SAM emissions (approximately 0.2 ppmvd in the exhaust gas for clean fuels).

5.2.5.3 Step 2 – Eliminate Technically Infeasible SAM Control Options

Use of clean fuels with inherently low sulfur content are inherent to the Project and technically feasible.

5.2.5.4 Step 3 – Rank Remaining SAM Control Options

No ranking of control options is required, as use of clean fuels with inherently low sulfur content is the only available and technically feasible control option for SAM emissions from the proposed CT units.

5.2.5.5 Step 4 – Evaluation of SAM Control Options

The top control option is being proposed for SAM emissions from the proposed CT units. Therefore, no further evaluation of the impacts of the control options is required.

5.2.5.6 Step 5 – Select SAM BACT for Combustion Turbines

No BACT floor exists for SAM emissions from the proposed CT units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

SAM BACT for the proposed CT units is based on use of clean fuels with inherently low sulfur content. GPC proposes to only fire pipeline quality natural gas and distillate oil in the proposed CT units.

Pipeline quality natural gas, as defined in 40 CFR 72.2, contains less than 0.5 grains sulfur per 100 standard cubic feet, while distillate oil contains less than 15 ppm sulfur. Based on the sulfur content of each fuel, SAM emissions will be less than 0.0022 lb/MMBtu when firing natural gas and 0.0024 lb/MMBtu when firing distillate oil.

The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

STF-PIA-10-9 Attachment

5.2.6 Greenhouse Gases – CO_2

5.2.6.1 Formation

GHG emissions that result from the combustion of clean fuels in the proposed CT units include CO_2, CH_4, and N_2O. CO_2 is a necessary product of combustion from fuels containing carbon. For example, the theoretical combustion equation for CH_4, the primary component of natural gas, is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

Consequently, CO_2 emissions are an essential and intended product of the chemical reaction between the fuel and the oxygen in which it burns and are not a byproduct caused by impurities in the fuel or by incomplete combustion.

5.2.6.2 Step 1 – Identify CO_2 Control Options

GPC searched EPA's control technology database, considered relevant new and proposed federal and state emission standards, reviewed recently issued new source review permits for similar sources, and relied on Southern Company's experience as a leader in low carbon technology research and innovation to identify potential control options for CO_2 emissions from the proposed CT units. The RBLC database lists technologies and corresponding emission limits that have been approved by regulatory agencies in permitting actions. These results are summarized in **Appendix E**, Tables E-13 and E-14. Based on the RBLC search results, no add-on control options were identified. Many facilities listed some variation of use of clean fuels (natural gas and distillate oil), efficient design, and good combustion practices as BACT for CO_2 emissions. Such control options form the basis for GHG BACT for similar advanced class simple-cycle CTs, such as Canal Generating Station Unit 3 in Massachusetts and at the Lincoln Combustion Turbine Station Emission Unit 19 in North Carolina. In addition, this analysis considers co-firing low-GHG hydrogen and carbon capture and sequestration (CCS) as potential control options from the proposed CT units based on a recent EPA rulemaking proposal. Each of these control options is discussed in further detail below.

This BACT analysis does not consider certain inherently lower-emitting processes or designs that would fundamentally redefine the proposed source, including solar, battery energy storage systems (BESS), or BESS plus solar, consistent with EPA's response to comments on the Palmdale Hybrid Power Project.[16] Nonetheless, more solar and energy storage resources have been proposed to the Georgia Public Service Commission (PSC) along with the proposed CT units as part of GPC's comprehensive plan to address Georgia's rapidly growing energy needs. This proposal is in addition to the 3,070 MW of renewable resources currently delivering energy to GPC customers today, the 2,330 MW of additional renewable projects already under contract or development and anticipated to be online by the end of 2024, and the 2,300 MW of renewable resources approved by the PSC as part of the 2022 IRP and expected to be online by 2029. For similar reasons, this BACT analysis does not consider combined-cycle technology since this design would fundamentally redefine the proposed source. Combined-cycle technology does not provide the operational flexibility and quick-start capability that the Project provides, which supports the integration of intermittent, weather-dependent renewable resources and to provide peaking power. Ultimately, energy storage systems, including BESS, will play an increasingly important role in ensuring the reliability of the electric system for

[16] U.S. EPA Environmental Appeals Board decision, *In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, at 727 (Sept. 17, 2012) (citing EPA Region 9, Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project, at 3 (Oct. 2011) ("Finally, we [EPA] note that the incorporation of the solar power generation into the BACT analysis for this facility [Palmdale] does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant considers all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project.").

customers. However, GPC cannot currently rely on short-duration storage to meet its capacity needs. The proposed simple-cycle CT units provide the operational flexibility and quick-start capability that complement BESS in support of continued integration of renewable resources and to provide peaking power when needed. Additionally, the proposed CT units can be constructed in the short time frame needed to ensure new generation is operational to help address GPC's capacity needs identified in the Integrated Resource Plan update GPC submitted to the PSC in October 2023. CT units with combined-cycle technology cannot reasonably be operated as peaking units due to the slower startup time and need to maintain the unit in a state allowing for hot startup to reduce the time needed to speed-up, synchronize, and load the steam turbine, and cannot be constructed and operational in time to address GPC's capacity needs.[17] Therefore, combined-cycle technology is excluded from being listed as a potential control option since this technology would disrupt the fundamental business purpose of the proposed facility. This approach is consistent with EPA's issuance of a GHG PSD permit for the Guadalupe Generating Station in 2014.[18]

Use of Clean Fuels

EPA established the use of clean fuels as the best system of emission reduction (BSER) for new non-baseload CT units in NSPS Subpart TTTT. Use of clean fuels (natural gas and distillate oil) is inherent to the Project and serves as the BACT "floor" for the proposed CT units. Although EPA has proposed a new NSPS standard based on other control options for intermediate and baseload combustion turbines, that proposal is not yet final and therefore does not establish a mandatory floor for BACT, as discussed further below. Nevertheless, those control options are evaluated as part of the BACT analysis below.

Efficient Design

Efficient design is also inherent to the Project. The CT technology that will be used for the Project represents the next evolution in technology advancements over previous designs. Among other things, the advancements associated with the proposed CT units include higher pressure ratios, increased firing temperatures, and advanced thermal barrier coatings. The proposed CT units will also be equipped with evaporative cooling, which reduces the power required to compress the inlet air before it is used in combustion, thus increasing overall efficiency during certain operating conditions, especially on hot days. Additionally, the proposed CT units will be equipped with sophisticated instrumentation to control all aspects of operation, including fuel flow rate and burner operations, to achieve high efficiency and low emissions.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are also inherent to the Project. As the proposed CT units are operated, they will inevitably experience performance degradation and efficiency loss over time. As a preventative measure, the proposed CT units will be equipped with a high efficiency filtration system for the inlet air which reduces contaminants that cause compressor fouling, one of the primary causes of efficiency loss. To address the compressor fouling that does occur, the proposed CT units will be equipped with a water wash system to clean the compressors while on- or off-line.

The proposed CT units will also be maintained under a maintenance program designed and implemented by the original equipment manufacturer (OEM). Maintenance programs are important for efficiency as well as long-term reliability and are based on a schedule determined by the number of hours of operation and/or turbine starts. Such programs commonly include three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles and include combustor tuning to maintain highly efficient, low-emissions operation. Hot gas path

[17] Startup for the proposed CT units is not expected to not exceed 32 to 49 minutes, depending on the fuel being utilized. However, "cold" startup for GPC CTs with combined-cycle technology may take as long as 300 minutes, while "hot" startups may take as long as 85 to 115 minutes, depending on the unit. See McDonough-Atkinson Steam-Electric Generating Plant Permit No. 4911-067-0003-V-05-0 and McIntosh Combined-Cycle Facility Permit No. 4911-103-0014-V-06-0.
[18] U.S. EPA Region 6, Statement of Basis for Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Guadalupe Power Partners, Guadalupe Generating Station, Permit Number: PSD-TX-1310-GHG (Oct. 2014).

inspections and major inspections occur on manufacturer-prescribed schedules and involve inspection and possible replacement of internal parts, including compressor or turbine blades, to restore lost performance.

Use of Low-GHG Hydrogen

On May 23, 2023, EPA proposed NSPS Subpart TTTTa, which would apply to the proposed CT units if finalized as proposed.[19] In this proposal, EPA proposed co-firing 30% low-GHG hydrogen by 2032 as BSER for both intermediate load and baseload CT units, with an increase to 96% low-GHG hydrogen by 2038 for baseload units. Low-GHG hydrogen requires the production of the hydrogen fuel through use of a low CO_2 emission technology, such as a renewable energy-powered process or a fossil fuel-powered process paired with carbon capture and storage. Co-firing low-GHG hydrogen is evaluated as a potential control option in this BACT analysis based on proposed NSPS Subpart TTTTa. However, in the proposal, EPA affirmed that "a proposed NSPS does not establish the BACT floor for affected facilities seeking a PSD permit."[20] Therefore, use of clean fuels (natural gas and distillate oil) remains the BACT "floor" until EPA finalizes NSPS Subpart TTTTa (and remains the BACT floor for peaking units which operate with an annual capacity factor less than 20%, if finalized as proposed).

The OEM claims the proposed CT units will be capable of co-firing 30% low-GHG hydrogen. However, the low-GHG hydrogen fuel itself is not available and therefore should not be considered further for the purposes of BACT. GPC has nonetheless evaluated technical feasibility and other factors for this control option.

Carbon Capture and Sequestration

In its recent Subpart TTTTa proposal, EPA also deemed carbon capture and storage (CCS) to be a potential add-on control option for base load CT units. Therefore, CCS is evaluated as a potential control option in this BACT analysis.[21] CCS requires the integration of a variety of processes and equipment to separate and capture CO_2 from the exhaust stream, compress and transport the CO_2 to a suitable storage location, and pump the CO_2 deep underground.

Based on the discussion above, the following potential control options for CO_2 emissions from the proposed CT units were considered as part of this BACT analysis:

- Use of clean fuels (natural gas and distillate oil);
- Efficient design;
- Good combustion, operating, and maintenance practices;
- Use of low-GHG hydrogen as a fuel; and
- Carbon capture and sequestration (CCS).

The technical feasibility of each of these control options is discussed in the following section.

[19] 88 Fed. Reg. 33240 (May 23, 2023). If finalized as proposed, each proposed CT unit would be part of the intermediate load subcategory if operated at a capacity factor up to its design efficiency and thus subject to Phase I and II standards, where Phase II is based on co-firing 30% low-GHG hydrogen by 2032.

[20] *Id* at 33407-08.

[21] GPC's evaluation also included consideration of partial CCS as a potential control alternative. However, GPC's analysis determined that, to be effective, a partial CCS strategy would still require the installation of the same equipment so that periods of operation with full capture could offset inevitable performance and reliability issues associated with CCS on a simple-cycle CT unit. Given that the cost would be similar, but emission reductions would be lower, GPC determined that partial CCS would be less cost-effective than full CCS, and partial CCS would also present the same challenges as full CCS with respect to availability and applicability under Step 2. Therefore, since full CCS was determined to be unavailable in Step 2 and cost-ineffective in Step 4, the same conclusions were reached for partial CCS as well. Accordingly, this analysis does not expressly include additional details on the evaluation of partial CCS as a potential control option.

STF-PIA-10-9 Attachment

5.2.6.3 Step 2 – Eliminate Technically Infeasible CO_2 Control Options

Use of Clean Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices

Use of clean fuels, efficient design, and good combustion, operating, and maintenance practices are all inherent to the Project and technically feasible.

Use of Low-GHG Hydrogen

Hydrogen co-firing is a promising, but still emerging, technology. However, for purposes of a BACT determination, low-GHG hydrogen is not technically feasible because it is neither "applicable" nor "available" as defined by EPA.

Hydrogen co-firing is an emerging technology that has not been demonstrated in practice. Hydrogen can only be co-fired with natural gas because turbine manufacturers have indicated that hydrogen cannot be co-fired with distillate oil. To date, there have been a handful of known test burns of hydrogen blended with natural gas in CTs, including at one of the units at GPC's McDonough-Atkinson Steam-Electric Generating Plant (Plant McDonough). However, most, if not all, of these test burns were conducted for short periods of time using temporary blending systems due to the lack of hydrogen availability.[22] Moreover, the test burns that have been conducted have used hydrogen that would not qualify as low-GHG hydrogen, due to the even more limited availability of low-GHG hydrogen, and therefore did not result in any meaningful reduction in overall GHG emissions. Since these test burns were only temporary in nature and failed to use low-GHG hydrogen, the tests do not suggest that this control option is applicable. According to EPA guidance, applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations."[23] Since hydrogen co-firing has not been demonstrated in practice, it does not constitute a demonstrated and potentially applicable control technology for the proposed CT units.

With respect to "availability," low-GHG hydrogen cannot be obtained through any known commercial channels in the vicinity of the Project. Pipeline gas quality specifications, in particular higher heating value (HHV), will prevent blending the volumes of hydrogen that would be required by the proposed CT units into the existing natural gas infrastructure that serves Plant Yates.[24] While the 2021 Infrastructure Investment and Jobs Act (IIJA) and the 2022 Inflation Reduction Act (IRA) provide funding opportunities and tax credits to drive down the cost of and increase production, processing, delivery, storage, and use of low-GHG hydrogen, these incentives have yet to make low-GHG hydrogen commercially available. Other incentives, including California's Low Carbon Fuel Standard (LCFS) program, which makes credits available for use of hydrogen made with "clean electricity" as a low carbon transportation fuel in fuel cell vehicles, actually divert what little low-GHG hydrogen is currently produced for use in niche markets. The US Department of Energy (DOE) recently announced $7 billion in funding to launch seven Regional Clean Hydrogen Hubs (H2Hubs) across the nation, none of which will be located in Georgia or in the southeastern US. Additionally, the US Treasury has delayed issuing guidance on how to qualify for the low-GHG hydrogen production tax credits available under Section 45V of the Internal Revenue Code (IRC), causing uncertainty for project development. GPC is unaware of any developers planning to build out the significant infrastructure necessary to make use of low-GHG hydrogen a commercially available control option for the proposed CT units. Thus, low-GHG hydrogen is

[22] For example, the short-term test burn at Plant McDonough was conducted at a maximum of approximately 20% hydrogen co-firing by volume for less than a full hour. The test was conducted on a single train of a 2-on-1 combined-cycle unit and required significant on-site oversight and involvement by the OEM.

[23] EPA Draft New Source Review Workshop Manual, at B.11 (Oct. 1990).

[24] The pipeline specification is 980 Btu/scf HHV. See Transcontinental Gas Pipe Line Company, LLC, FERC Gas Tariff, Fifth Revised Volume No. 1, Part IV - General Terms and Conditions, Section 3 – Quality, 3(b). Blending 30% low-GHG hydrogen with natural gas results in a heating value of approximately 810 Btu/scf. However, the pipeline specification applies to the gas offered at the point of delivery (e.g., just upstream of the point of injection), making direct injection of hydrogen impossible.

not an available control option, and therefore cannot be an applicable control option for the CT units. Accordingly, low-GHG hydrogen is not technically feasible.

Even though co-firing low-GHG hydrogen is not technically feasible for a BACT determination, GPC has ranked this control option among the options being considered and evaluated for CO_2 emissions control effectiveness from the proposed CT units.

Carbon Capture and Sequestration

CCS is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for safe, secure, and permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped and cannot enter the atmosphere. Captured CO_2 can also be transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

For CCS to be technically feasible, each individual step in the process (capture and compression, transportation, and storage) must be technically feasible. The integrated suite of components must also be technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the units. Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

To date, CCS has not been demonstrated in practice on a combustion turbine. Furthermore, no research and development has been completed for implementation of CCS on simple-cycle CTs because the exhaust gas from a simple-cycle CT is too hot for post-combustion carbon capture and requires significant cooling for amine-based solvent or membrane separation. Therefore, CCS is not an “applicable” control option. EPA has specifically recognized the unresolved challenges associated with attempting to apply CCS to simple-cycle combustion turbines like those included in the Project.[25] While the exhaust gas could be cooled with combined-cycle technology, this would fundamentally redefine the proposed source as discussed in Step 1.

Although CCS is not technically feasible for a BACT determination for CO_2 emissions from the proposed CT units, GPC has ranked this control option among the options being considered and evaluated for CO2 emissions control effectiveness from the proposed CT units.

5.2.6.4 Step 3 – Rank Remaining CO_2 Control Options

The following ranks the control options under consideration by control effectiveness:

- CCS – up to 90% (included, although not applicable)
- Co-firing low-GHG hydrogen – up to 16% (at 30% hydrogen by volume) (included, although not available)
- Use of clean fuels, efficient design, and good combustion practices – these control options are inherent to Project.

5.2.6.5 Step 4 – Evaluation of CO_2 Control Options

Carbon Capture and Sequestration

[25] 88 Fed. Reg. at 33286 (May, 23, 2023) (“[C]urrently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to do this is to use a HRSG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit.”).

While CCS is not technically feasible for the proposed CT units, this control option is also eliminated from this BACT analysis based on the unreasonable estimated cost of control. The cost associated with CCS is estimated for each of the individual processes – capture and compression, transportation, and storage – using published studies and government resources and is presented in **Appendix F** and discussed in the following sections.

Cost of Control – Capture and Compression

For capture and compression, the 2022 DOE/NETL report *Cost and Performance Baseline for Fossil Energy Plants Volume 1* and the 2020 Electric Power Research Institute (EPRI) report *Natural Gas Combined Cycle Power Plants with Post Combustion CCS (# 3002016289)* were used to estimate costs per ton of CO_2 captured. Because there are no known public studies assessing CO_2 capture costs for a simple-cycle CT, costs for CTs with combined-cycle technology were used as an approximation, with appropriate adjustments as detailed further below. Two independent studies were evaluated because the estimated costs of CO_2 capture and compression from combined-cycle CTs vary in published studies.

Capture and compression costs are significantly higher for simple-cycle CTs than for combined-cycle technology for at least four reasons. First, as previously mentioned, the exhaust gas from the proposed CT units is too hot for post-combustion carbon capture and requires significant cooling for CO_2 separation, which would necessitate additional expense compared to the combined-cycle based costs in the reference studies.[26] Second, the exhaust gas from the proposed CT units is tempered with ambient air for the SCR systems, which makes the volume of exhaust gas for which the front-end capture equipment must be sized roughly 2.7 times larger than the two H-class CTs with combined-cycle technology included in the public references (EPRI and NETL). Third, the amount of CO_2 removed from the proposed CT units' exhaust gas would be almost double that of the CO_2 removed for the combined-cycle units in the reference studies, making the back-end solvent regeneration and compression equipment significantly more expensive. Finally, the available public studies do not account for first-of-a-kind issues and associated costs that will inevitably be encountered by the first implementations of carbon capture on a CT.

Cost estimates for CO_2 capture have been adjusted to account for the different physical and chemical characteristics of the exhaust gas of the proposed CT units compared to the combined-cycle units addressed in the published studies. For example, front-end CO_2 capture equipment such as the direct contact coolers and absorbers that process flue gas would have to be considerably larger vessels or multiple vessels in parallel. Back-end CO_2 capture equipment for solvent regeneration and CO_2 compression would also have to be considerably larger or multiple pieces of equipment in parallel. Finally, the additional cooling duty required for the exhaust gas from the proposed CTs units would be over 10 times that of a comparable CT with combined-cycle technology.

Based on these considerations, a reasonable engineering estimate was made that the capital cost for a CO_2 capture system for the proposed CT units would be 100% higher than the reference CTs with combined-cycle technology. Put another way, the volume of exhaust gas from one of the proposed CT units (with tempering air) is nearly the same as the volume of exhaust gas from two CTs in a 2-on-1 combined-cycle configuration (without tempering air) referenced in the published studies. Therefore, since the Project consists of three proposed CT units, it is reasonable to estimate that the total capital costs for CO_2 capture and compression for the proposed project would be approximately three times that of the capital costs from the 2-on-1 reference cases, which equates to nearly $3 billion in total overnight costs (TOC).

Based on these TOC, GPC estimates the total annualized costs of capture and compression from the proposed CT units to be at least $140 per ton of CO_2 captured. Higher actual costs are expected because this

[26] Tempering air, equivalent to approximately 60 percent of the exhaust mass flow rate from a proposed CT unit, is needed to make SCR an applicable (technically feasible) control option. For CCS, 20 times more ambient air would be needed to further temper the exhaust gas from the proposed CT units for CO_2 separation.

cost estimate does not include additional costs itemized below that would also be expected for CO_2 capture on a simple-cycle CT:

- Additional station service costs associated with incremental flue gas fans, solvent pumps, and CO_2 compressors,
- Additional fixed and variable operating and maintenance (O&M) costs associated with the larger / additional equipment, additional exhaust gas, and incremental solvent usage,
- Additional capital and O&M costs to provide a source of steam for solvent regeneration (e.g., a package boiler or small standalone CT with heat recovery steam generator, each of which would separately release additional CO_2 emissions), and
- Additional capital and O&M costs associated with large lean and rich solvent storage tanks, pumps, heat exchangers, and other equipment that would be necessary to facilitate capture during quick startups and intermittent operations.

Cost of Control – Transportation (Pipeline) and Storage

Transporting CO_2 and pumping it into deep geological formations is necessary for long-term secure storage. The proposed Project is in a region generally characterized by Piedmont geology, which is unsuitable for CO_2 storage due to the crystalline nature of the rocks, which results in a lack of permeability and porosity, rock properties required for injection and storage of CO_2. Therefore, captured and compressed CO_2 will need to be transported to the nearest suitable geologic sequestration site (presuming it is feasible to do so). Potentially suitable geologic formations include active and abandoned oil and gas fields, un-mineable coal seams, basalt formations, and deep saline reservoirs. However, no oil or gas fields exist in Georgia and there are no un-mineable coal seams or basalt formations in proximity to the proposed Project. Therefore, deep saline reservoirs are the only option for storage in the area.

Based on Southern Company's knowledge of geologic investigations across the southeastern U.S., Baldwin County, Alabama is presumed to provide a potentially feasible site for carbon sequestration for the proposed Project. It has also been announced that Denbury and Exxon are investigating the area for development of a CO_2 storage hub. Accordingly, Baldwin County could provide a suitable destination for CO_2 emissions from the proposed CT units and GPC has determined the cost of control for transporting CO_2 for storage from the proposed Project to this location.

The total annualized cost of CO_2 pipeline installation and operation necessary to transport compressed CO_2 from the proposed Project to Baldwin County for geological storage was estimated using the *FECM/NETL CO2 Transport Cost Model (2023): Description and User's Manual (DOE/NETL-2023/4385)*. The model was used to determine the optimal pipeline diameter and number of booster pump stations in order to estimate the minimum expected cost of CO_2 transportation. The pipeline costs include pipeline construction, other related capital costs, and operation and maintenance (O&M) costs.

For cost estimation purposes, a pipeline length of 280 miles was used (based on driving distance). The FE/NETL CO_2 Transport Cost Model determined that a 12-inch diameter pipeline with seven integrated pumping stations would be the least-cost option for CO_2 emissions captured from the proposed CT units.

Because the expected service costs for the Denbury/Exxon CO_2 storage hub previously mentioned are not publicly available, storage costs were estimated based on Southern Company's experience gained during the Alabama Power Company (APC) Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 project.[27]

[27] Southern Company built and operated a 25 MW coal slipstream amine post-combustion capture plant at APC Plant Barry in 2011. CO_2 subsurface pumping operations began in 2012 and concluded in 2014. The project included drilling two injection wells and two observation wells into the Paluxy Formation (a deep saline formation) located in Citronelle Dome, geologically above the Citronelle Oil Field in South Alabama. The project pumped nearly 120,000 tonnes of CO_2 over three years. The project included construction and operation of a 12-mile pipeline that connected Plant Barry to the Citronelle Dome injection site and provided data for DOE and industry on how effective monitoring and verification protocols for geologic storage could be deployed in the field.

While the estimate represents expected "self-build" costs, it was assumed these costs would represent the lowest potential cost of third-party storage, since the costs do not include profit for the hub itself.

Based on above, the total annualized cost for transportation of captured CO_2 emissions from the proposed CT units and storage is approximately $75 million per year, or $32 per ton of CO_2 captured.

Cost of Control – Total Annualized Costs for Capture and Compression, Transportation, and Storage

The total annualized costs to capture and compress, transport, and store CO_2 emissions from the proposed CT units is estimated to be at least $172 per ton CO_2 captured, without including the additional costs noted above.[28] On a levelized cost of electricity (LCOE) basis, this equates to approximately $84/MWh. With TOC in excess of $3 billion, the cost of control for CCS are demonstrated to be exorbitant and unreasonable on an absolute, cost effectiveness, or LCOE basis.

Cost of Control – IRA Tax Credits

The 2022 IRA extended and increased the tax credit available for CCS under Section 45Q of the IRC. Beginning in 2023, these incentives may include up to 12 years of credits of $85 per metric tonne ($77 per ton) of CO_2 geologically sequestered for projects that commence construction prior to 2033. On a normalized basis consistent with the cost of control evaluation provided in **Appendix F**, 45Q would provide a credit of approximately $68 per ton. This normalized credit value is conservative in that it includes escalation for inflation, consistent with 45Q, as well as a "gross-up" for tax considerations specific to Southern Company. However, cost items such as inflation and tax gross-up are not part of EPA's "overnight" costing methodology and are normally excluded in estimating costs. If inflation and tax gross-up are excluded, 45Q would provide a normalized credit value of approximately $47 per ton.

As noted above, EPA guidance indicates that income tax considerations should be excluded from cost analyses.[29] Moreover, including the 45Q credit in the CCS cost evaluation implies that the proposed CT units may operate solely to generate credits to improve the economics of CCS, which is inconsistent with and disruptive to the intended business purpose of the proposed project. Therefore, 45Q credits should not be included in estimating the cost of control. Nonetheless, GPC calculated the cost per ton for CCS assuming application of the 45Q credit as at least $105 to $125 per ton, which also does not account for the additional capital and O&M costs noted above.

Use of Low-GHG Hydrogen

While co-firing low-GHG hydrogen is not technically feasible for the proposed CT units, this control option is also eliminated from this BACT analysis based on the unreasonable estimated cost of control and significant energy penalties that would be incurred, as discussed in the following sections.

Cost of Control – Co-firing Low-GHG Hydrogen

EPA proposes to define "low-GHG hydrogen" in Subpart TTTTa as "hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45

[28] GPC's evaluation also included consideration for CCS as applied to the proposed CT units when firing distillate oil. However, GPC determined that, to be effective, a CCS strategy would still require the installation of the same equipment to be adequately sized to capture CO_2 emissions that result from firing either natural gas or distillate oil at the baseload rating for each fuel. Given similar capital costs, higher O&M costs due to differences in capacity, heat rate, and fuel costs, and that distillate oil would only be used when natural gas is unavailable, CCS would be less cost-effective if evaluated for oil-firing alone. Accordingly, this analysis does not expressly include additional details on the evaluation of CCS as applied to the proposed CT units when firing distillate oil.

[29] EPA, *Draft New Source Review Workshop Manual*, at B.11 (Oct. 1990) ("It is also recommended that income tax considerations be excluded from cost analyses. This simplifies the analysis. Income taxes generally represent transfer payments from one segment of society to another and as such are not properly part of economic costs.")

kilograms of CO_2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H2), determined using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model)."[30] Water electrolysis is currently the most realistic pathway for producing low-GHG hydrogen. According to Lazard, the current production cost for hydrogen made from electrolysis with renewable power is approximately $6/kg.[31] Assuming this as the delivered cost to the project site, the total annualized cost for co-firing 30% low-GHG hydrogen in the proposed CT units is approximately $72 million per year, or $517 per ton of CO_2. Accordingly, the cost of control for co-firing low-GHG hydrogen is unreasonable.[32,33]

Energy Impacts – Co-firing Low-GHG Hydrogen

Electrolytic production of hydrogen requires a significant amount of electricity. In order to burn a 30% hydrogen blend in the proposed CT units, over 300 tons per day of hydrogen must be produced and delivered to the project site. In order to produce this amount of hydrogen, it would take over 600 MW of polymeric electrolyte membrane (PEM) electrolyzers based on their expected performance (55 kWh per kg hydrogen).[34] This is equivalent to nearly 50% of the capacity of the proposed CT units (on gas). However, in order to produce low-GHG hydrogen, the electrolyzers would need to be powered by renewable energy such as solar. Over 2,500 MW of solar capacity covering an area of more than 12,000 acres would be needed to produce enough low-GHG hydrogen to burn a 30% hydrogen blend in the proposed CT units.[35] This theoretical amount of solar power would need to be fully dedicated to producing hydrogen for the proposed project and would not be available to address Georgia's growing capacity needs. When taking into account these significant energy penalties, BACT for CO_2 emissions from the proposed CT units should not be based on co-firing low-GHG hydrogen, particularly in light of Georgia's unprecedented increase in the demand for energy in the state that has resulted in the specific need for the new CT units.

Use of Clean Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices

There are no source-specific energy, economic, or environmental impacts that would make clean fuels, efficient design, and good combustion, operating, and maintenance practices inappropriate for BACT for CO_2 emissions from the proposed CT units.

5.2.6.6 Step 5 – Select CO_2 BACT for Combustion Turbines

CO_2 BACT for the proposed CT units is based on the use of clean fuels, efficient design, and good combustion, operating, and maintenance practices. Consistent with how BACT has been handled for other simple-cycle CT units, GPC is proposing to limit 12-month rolling GHG emissions for each proposed CT unit to less than 1,020,020 tons per year on a CO_2e basis, including periods of startup, shutdown, and fuel switching. This limit is also intended to cover emissions of CH_4 and N_2O based on the BACT determinations for those pollutants, which are summarized below.

Compliance with the proposed GHG BACT limit will be demonstrated by continuously monitoring heat input according to 40 CFR Part 75, Appendix D, and using emission factors to calculate monthly emissions. The

[30] 88 Fed. Reg. 33304 (May, 23, 2023).

[31] Lazard's Levelized Cost of Hydrogen Analysis, at 26 (Apr. 2023), https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

[32] Co-firing 30% low-GHG hydrogen at baseload rating reduces natural gas consumption by approximately 16% on a heat input basis and results in a proportionate reduction in CO_2 emissions (~140,000 tons).

[33] GPC acknowledges that co-firing low-GHG hydrogen may reduce emissions of CO, VOC, PM, and H_2SO_4 and determined that, relative to GHG emissions, emission reductions of these pollutants would be even less cost-effective since they are emitted in significantly lower amounts.

[34] Technical Targets for Proton Exchange Membrane Electrolysis, https://www.energy.gov/eere/fuelcells/technical-targets-proton-exchange-membrane-electrolysis.

[35] Based on a capacity factor of 24.7%. Energy Information Administration, State Energy Data System (SEDS), Table F38: Capacity factors and usage factors at electric generators: total (all sectors), 2022, https://www.eia.gov/State/Seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_cf.html&sid=GA.

emission factor for CO_2 will be based on 40 CFR Part 75, Appendix G, Eq. G-4, while emissions of CH_4 and N_2O will be based on the current emission factors in 40 CFR Part 98, Table C-2 and the current global warming potentials in 40 CFR Part 98, Table A-1.

5.2.7 Greenhouse Gases – CH_4

For the proposed CT units, the contribution of CH_4 to total CO_2e emissions is negligible and therefore should not warrant a detailed BACT review. Nonetheless, the following top-down analysis is provided for CH_4 emissions from the proposed CT units.

5.2.7.1 Formation

Emissions of CH_4 may occur because of incomplete combustion of methane and hydrocarbons in fuel.

5.2.7.2 Step 1 – Identify Available CH_4 Control Options

As discussed above, CH_4 emissions may occur because of incomplete combustion. Good combustion practices are an available control option to reduce CH_4 emissions from the proposed CT units.

Catalyst providers do not offer products to control CH_4 emissions from combustion turbines due to the very low concentrations present in exhaust streams. Additionally, the reaction rate for hydrocarbons over an oxidation catalyst is a strong function of chain length making post-combustion oxidation of CH_4 particularly difficult. Therefore, good combustion practices are the only available control option for CH_4 emissions from the proposed CT units.

5.2.7.3 Step 2 – Eliminate Technically Infeasible CH_4 Control Options

Good combustion practices are the only available control option for CH_4 emissions from the proposed CT units and are technically feasible.

5.2.7.4 Step 3 – Rank Remaining CH_4 Control Options

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for CH_4 emissions from the proposed CT units.

5.2.7.5 Step 4 – Evaluation of CH_4 Control Options

The top control option – good combustion practices – is proposed for emissions of CH_4 from the proposed CT units. Therefore, no further evaluation of the CH_4 control options is required.

5.2.7.6 Step 5 – Select CH_4 BACT for Combustion Turbines

Good combustion practices are selected as BACT for CH_4 emissions from the proposed CT units. GPC is proposing that a separate numerical limit for CH_4 emissions is unnecessary because CH_4 emissions are included in the proposed GHG limit expressed in CO_2e determined to be BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 25 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

5.2.8 Greenhouse Gases – N_2O

For the proposed CT units, the contribution of N_2O to total CO_2e emissions is also negligible and therefore should not warrant a detailed BACT review. Nonetheless, the following top-down analysis is provided for N_2O emissions from the proposed CT units.

5.2.8.1 Formation

There are five (5) primary pathways of NO_X production in combustion turbines: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using DLN combustors, the N_2O pathway is the prevailing mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with N_2O, creating N_2 and NO.[36] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed, the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like those in DLN combustors are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream, all of which are common NO_X control measures.[37] Therefore, reductions in NO_X can result in incremental increases in N_2O emissions.

5.2.8.2 Step 1 – Identify Available N_2O Control Options

Good combustion practices are an available control option to reduce N_2O emissions from the proposed CT units. As discussed above, N_2O formation is limited during complete combustion, since most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.

Additionally, N_2O catalysts are a potential control option, as they have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[38] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with an N_2O catalyst followed by ammonia injection and a NO_X catalyst.

5.2.8.3 Step 2 – Eliminate Technically Infeasible N_2O Control Options

N_2O catalyst providers do not offer products to control N_2O emissions from combustion turbines due to the very low N_2O concentrations present in exhaust streams (approximately 5 ppm).[39]

Since N_2O catalysts are not available, good combustion practices are the only available control option and are technically feasible.

5.2.8.4 Step 3 – Rank Remaining N_2O Control Options

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for N_2O emissions from the proposed CT units.

5.2.8.5 Step 4 – Evaluation of N_2O Control Options

The top control option – good combustion practices – is being proposed for emissions of N_2O from the proposed CT units. Therefore, no further evaluation of the N_2O control options is required.

[36] Angello, L., Electric Power Research Institute, Fuel Composition Impacts on Combustion Turbine Operability, March 2006.
[37] American Petroleum Institute, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, February 2004

[38] N_2O Emissions from Adipic Acid and Nitric Acid Production, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

[39] Emissions of Nitrous Oxide from Combustion Sources, in Progress and Energy and Combustion Science 18(6): pages 529- 552, December 1992, found at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources

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5.2.8.6 Step 5 – Select N_2O BACT for Combustion Turbines

Good combustion practices are selected as BACT for N_2O emissions from the proposed CT units. GPC is proposing that a separate numerical limit for N_2O emissions is unnecessary because N_2O emissions are included in the proposed GHG limit expressed in CO_2e determined to be BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 298 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

5.3 Emergency Generator and Fire Water Pump Engine BACT Review

Associated equipment associated with the Project includes:

- One (1) diesel fuel-fired emergency generator with a standby rating of approximately 3250 kW (4360 hp), and
- One (1) diesel fuel-fired fire water pump engine with a continuous rating of approximately 260 kW (350 bhp).

5.3.1 General

In 1994, EPA began regulating emissions of NO_X, PM, CO, and nonmethane hydrocarbons (NMHC) from nonroad engines through a phased approach and has since issued multiple tiers of emission standards for various categories of engines. For new and in-use nonroad compression ignition (CI) engines, EPA issued four tiers of emission standards: Tiers 1, 2, 3, and 4. Once EPA sets emission standards for an engine category, manufacturers must produce engines that meet those standards within the timeframe of the corresponding implementation schedule. The original Tier 1, 2, and 3 standards were adopted in 40 CFR Part 89. EPA has since migrated regulatory requirements for these engines to 40 CFR part 1039 along with the Tier 4 standards.

Stationary engines are generally built to the same specifications as nonroad engines and are subject to the same tiered emission standards through NSPS Subpart IIII. To meet these standards, manufactures employ one of two types of emission control strategies: engine-based technologies and aftertreatment-based technologies. Engine-based technologies include inlet air cooling, fuel injection rate controls, injection timing retard, exhaust gas recirculation, control of air/fuel ratio, and control of air consumption. Collectively, these technologies are referred to as engine design, combustion controls, and good combustion practices, and are the basis for current Tier 2 and Tier 3 engine standards. Aftertreatment-based technologies include the use of SCR and catalyzed diesel particulate filters (CDPF) in conjunction with ULSD and are the basis for the current Tier 4 standards.

NSPS Subpart IIII requires owners and operators of stationary CI internal combustion engines (ICE) that use diesel fuel to purchase engines certified to meet the emission standard applicable to the engine category for the same model year and maximum engine power as well as to use ULSD, with limited exceptions. The proposed emergency generator must be certified to Tier 2 standards, while the fire water pump engine must be certified to Tier 3 standards.[40] Once purchased, the engines and control devices must be operated and maintained according to the manufacturer's emission-related instructions. Therefore, the only available control options for the proposed emergency generator and fire water pump engine are those that are included with the purchase of an emergency generator certified to Tier 2 standards, a fire water pump engine certified to Tier 3 standards, or a non-emergency engine certified to Tier 4 standards and operated as if it were an emergency generator or fire water pump engine.

[40] See 40 CFR 60.4202(b)(2) for the emergency generator (Tier 2) and 40 CFR 60.4202(d), Table 4 to 40 CFR Part 60 Subpart IIII, and Table 3 to Appendix I in 40 CFR Part 1039 (Tier 3).

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5.3.2 Nitrogen Oxides

5.3.2.1 Formation

NO_X emissions from the proposed emergency generator and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency.

5.3.2.2 Step 1 – Identify NO_X Control Options

As discussed above, available control options for NO_X emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator, a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in **Appendix E**, Table E-15, there are several cases in which Tier 4 was listed as BACT for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

5.3.2.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.[41] Therefore, Tier 4 is also considered technically feasible.

5.3.2.4 Step 3 – Rank Remaining NO_X Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.3.2.5 Step 4 – Evaluation of NO_X Control Options

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for NO_X to be between ~$240,000 and $400,000 per ton when applied to emergency engines with similar power ratings.[42] Therefore, Tier 4 is eliminated from this BACT analysis for both the proposed emergency generator and fire water pump engine based on the unreasonable estimated annual cost of control.

5.3.2.6 Step 5 – Select NO_X BACT for Emergency Generator and Fire Water Pump Engine

NO_X BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase an emergency generator certified to Tier 2 standards and a fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump

[41] Annual Certification Data for Vehicles, Engines, and Equipment, Nonroad Compression Ignition (NRCI) Engines, available online at https://www.epa.gov/system/files/documents/2023-01/nonroad-compression-ignition-2011-present.xlsx.

[42] Cost per Ton for NSPS for Stationary CI ICE, Table 5, June 2004, available at https://www.epa.gov/sites/default/files/2014-02/documents/6-9-05_cost_per_ton_ci_nsps.pdf. In Table 4, EPA provides costs for NO_X adsorber technology as low as $13,500 per ton. However, since this technology is not listed as an aftertreatment device type in use for any Tier 4 certified engine in EPA's annual certification database (column Q), it is presumed that Tier 4 engines that reduce emissions of NO_X at this level of cost-effectiveness when used as emergency engines are not commercially available.

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engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel.

5.3.3 Carbon Monoxide

5.3.3.1 Formation

CO emissions from the proposed emergency generator and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency and complete combustion.

5.3.3.2 Step 1 – Identify CO Control Options

As discussed above, available control options for CO emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in **Appendix E**, Table E-16, there is one case in which Tier 4 was listed as BACT for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT. It should be noted, however, that the CO emission standard for Tier 2, 3, and 4 engines for the same engine category and model year with similar power ratings are identical (3.5 g/kW-hr).[43]

5.3.3.3 Step 2 – Eliminate Technically Infeasible CO Control Options

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered technical feasible.

5.3.3.4 Step 3 – Rank Remaining CO Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. However, in the case of CO, the emissions standard for each tier is the identical.

5.3.3.5 Step 4 – Evaluation of CO Control Options

In the 2005 NSPS Subpart IIII proposal, EPA generally stated that the use of add-on controls for emergency stationary CI ICE could not be justified due to the cost of the technology relative to the emission reduction that would be obtained.[44] EPA has previously estimated the cost effectiveness of Tier 4 control strategies for CO to be between ~$10,000 and $24,000 per ton when applied to non-emergency engines with similar power ratings that operate for at least 1,000 hours per year.[45] The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. This is especially true for the proposed emergency generator and fire water pump engine, which will be operated for a maximum of 200 and 500 hours per year, respectively. Therefore, Tier 4 is eliminated from this BACT analysis for both the proposed emergency generator and fire water pump engine based on the unreasonable estimated annual cost of control.

[43] See Tables 2 and 3 to Appendix I in 40 CFR Part 1039 for Tier 2 and 3 standards, respectively, and Table 1 of 40 CFR 1039.101 for Tier 4 final standards.

[44] 70 Fed. Reg. 39874 (July 11, 2005).

[45] US EPA, Alternative Control Techniques Document: Stationary Diesel Engines, Final Report, EPA Contract No. EP-D-07-019, Table 5-6, March 2010.

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5.3.3.6 Step 5 – Select CO BACT for Emergency Generator and Fire Water Pump Engine

CO BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase an emergency generator certified to Tier 2 standards and a fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel.

5.3.4 Volatile Organic Compounds

5.3.4.1 Formation

As with CO emissions, VOC emissions from the proposed emergency generator and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency and complete combustion.

5.3.4.2 Step 1 – Identify VOC Control Options

As discussed above, available control options for VOC (NMHC) emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in **Appendix E**, Table E-17, there are several cases in which Tier 4 was listed as BACT for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

5.3.4.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered technically feasible.

5.3.4.4 Step 3 – Rank Remaining VOC Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.3.4.5 Step 4 – Evaluation of VOC Control Options

In the 2005 NSPS Subpart IIII proposal, EPA generally stated that the use of add-on controls for emergency stationary CI ICE could not be justified due to the cost of the technology relative to the emission reduction that would be obtained. EPA has previously estimated the cost effectiveness of Tier 4 control strategies for VOC (THC) to be between ~$80,000 and $100,000 per ton when applied to non-emergency engines with similar power ratings that operate for at least 1,000 hours per year.[46] The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. This is especially true for the proposed emergency generator and fire water pump engine, which will be

[46] US EPA, Alternative Control Techniques Document: Stationary Diesel Engines, Final Report, EPA Contract No. EP-D-07-019, Table 5-5, March 2010.

operated for a maximum of 200 and 500 hours per year, respectively. Therefore, Tier 4 is eliminated from this BACT analysis for both the proposed emergency generator and fire water pump engine based on the unreasonable estimated annual cost of control.

5.3.4.6 Step 5 – Select VOC BACT for Emergency Generator and Fire Water Pump Engine

VOC BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase an emergency generator certified to Tier 2 standards and a fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel.

5.3.5 Particulate Matter

5.3.5.1 Formation

PM emissions from the proposed emergency generator and fire water pump engine may consist of inorganic matter present in the fuel (e.g., ash, metals, etc.) and high molecular weight unburned hydrocarbons (soot). Generally, the use of clean fuels with negligible ash and sulfur content, such as ULSD, in conjunction with engine design and operational features to promote complete fuel combustion, minimizes PM emissions.

5.3.5.2 Step 1 – Identify PM Control Options

As discussed above, in addition to use of ULSD, available control options for PM emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in **Appendix E**, Table E-18, there were no cases in which Tier 4 was identified as BACT for PM. GPC has nonetheless evaluated technical feasibility and other factors for this control option.

5.3.5.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine and exclusive use of ULSD is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered technically feasible.

5.3.5.4 Step 3 – Rank Remaining PM Control Options

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.3.5.5 Step 4 – Evaluation of PM Control Options

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for PM to be between ~$160,000 and $970,000 per ton when applied to emergency engines with similar power

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ratings.[47] Therefore, Tier 4 is eliminated from this BACT analysis for both the proposed emergency generator and fire water pump engine based on the unreasonable estimated annual cost of control.

5.3.5.6 Step 5 – Select PM BACT for Emergency Generator and Fire Water Pump Engine

PM BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase an emergency generator certified to Tier 2 standards and a fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions. The proposed emergency generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year. Additionally, both the proposed emergency generator and fire water pump engine will exclusively use ULSD as fuel.

5.3.6 Greenhouse Gases

5.3.6.1 Formation

As with the proposed CT units, GHG emissions that result from the combustion of ULSD in the proposed emergency generator and fire water pump engine include CO_2, CH_4, and N_2O.

5.3.6.2 Step 1 – Identify GHG Control Options

While some engine-based technologies may promote fuel efficiency, EPA's tiered emission standards for CI ICE do not address GHG emissions directly. Based on the RBLC search results provided in **Appendix E**, Table E-19, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generator and fire water pump engine. Instead, many facilities listed some variation of use of clean fuels (natural gas and distillate oil), good combustion practices, and limiting annual operating hours as BACT for GHG emissions.

Potential control options not considered in this BACT analysis included use of natural gas and CCS. Relative to ULSD, natural gas inherently results in lower GHG emissions on a heat input basis. However, natural gas cannot be stored onsite and may not be available during an emergency, including when the emergency itself is unavailability of natural gas. Because natural gas is less likely to be available in the emergency circumstances during which the emergency engines and fire pump are needed, that option will not be considered further in this analysis, as it would interfere with the intended function of the units.

Additionally, CCS should not be considered as a potentially available control option since GHG emissions from the proposed emergency generator and fire water pump engine are insignificant. CCS should only be considered as an available control option for facilities that emit CO_2 in larger amounts, or for industrial facilities with high-purity CO_2 steams, consistent with past EPA guidance.[48] GPC's analysis of CCS for the proposed CT units found CCS to be technically infeasible and the annual cost of control to be unreasonable. Applying CCS to these sources alone or in combination with the proposed CT units cannot reasonably be expected to change the outcome of that analysis. Accordingly, use of ULSD, good combustion practices, and limiting annual operating hours are the only potentially available control options for GHG emissions from the proposed emergency generator and fire water pump engine.

[47] Cost per Ton for NSPS for Stationary CI ICE, Tables 4 and 6, June 2004, available at https://www.epa.gov/sites/default/files/2014-02/documents/6-9-05_cost_per_ton_ci_nsps.pdf.

[48] US EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 32 (March 2011).

5.3.6.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Exclusive use of ULSD as fuel and limiting annual operating hours for the proposed emergency generator and fire water pump engine are inherent to the Project and technically feasible.

5.3.6.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required, as the exclusive use of ULSD as fuel and limiting annual operating hours are the only available and technically feasible control options for GHG emissions from the proposed emergency generator and fire water pump engine.

5.3.6.5 Step 4 – Evaluation of GHG Control Options

The top control options are being proposed for emissions of GHG from the proposed emergency generator and fire water pump engine. Therefore, no evaluation of the control options is required.

5.3.6.6 Steps 5 – Select GHG BACT for Emergency Generator and Fire Water Pump Engine

GHG BACT for the proposed emergency generator and fire water pump engine is based on the exclusive use of ULSD as fuel and limiting annual operating hours. The proposed emergency generator will be operated for emergency purposes for a maximum of 200 hours per year, including 100 hours per year for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year.

5.4 Diesel Storage Tank BACT Review

5.4.1 Volatile Organic Compounds

5.4.1.1 Characterization of Emissions

VOC emissions from storage tanks result from two mechanisms: evaporative losses during storage (referred to as breathing or standing losses) and losses during tank filling (known as working losses). Standing losses occur when organic compounds contained in the vapor headspace above the stored liquid expand are emitted from tank vents due to changes in temperature and barometric pressure. Emissions from working losses occur due to the change in tank liquid level that accompanies tank filling operations. As the liquid level increases, the vapor headspace is displaced from the tank vent. In both cases, emissions vary as a function of the vapor pressure of the stored liquid and atmospheric conditions at the tank location.

5.4.1.2 Step 1 – Identify VOC Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emission standards to identify potential control options for VOC emissions from the proposed diesel storage tank. Based on the RBLC search results provided in **Appendix E**, Table E-20, no add-on control options were identified. Many facilities listed work practice standards such as submerged filling and tank design, including the specific external surface color of the tank, as BACT for VOC emissions. Submerged filling reduces working losses from liquid storage tanks by eliminating splashing and reducing vapor displacement in the tank headspace. The use of light or reflective tank surface colors decreases breathing losses by reducing tank inventory temperature changes caused by solar energy absorptance through the tank shell.

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On October 4, 2023, EPA proposed NSPS Subpart Kc, which would apply to certain volatile organic liquid storage vessels, including petroleum liquid storage vessels.[49] Similar to the previous version of the standard, e.g., Subpart Kb, EPA proposed equipping tanks storing certain liquids with either a floating roof (internal or external) or a closed vent system routed to a control device (such as an adsorption system, flare, or vapor recovery unit) as BSER. If finalized as proposed, this standard would not apply to the proposed diesel storage tank because the vapor pressure of stored liquid (distillate oil) is so low. GPC has nonetheless evaluated technical feasibility and other factors for these control options, along with use of submerged filling and tank design.

5.4.1.3 Step 2 – Eliminate Technically Infeasible VOC Control Options

Use of submerged filling and light or reflective tank surface colors are inherent to the Project and technically feasible.

GPC could not identify a case where the remaining control options have been installed and operated successfully on the type of source under review. In prior BACT determinations, EPA affirmed that these control options are generally not effective for controlling low concentrations of VOC generated by diesel storage tanks.[50] Therefore, use of submerged filling and light or reflective tank surface colors are the only technically feasible control options.

5.4.1.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required, as use of submerged filling and light or reflective tank surface colors are the only available and technically feasible control options for VOC emissions from the proposed diesel storage tank.

5.4.1.5 Step 4 – Evaluation of VOC Control Options

The top control options – use of submerged filling and light or reflective tank surface colors – are being proposed for emissions of VOC from the proposed diesel storage tank. Therefore, no evaluation of the VOC control options is required.[51]

5.4.1.6 Step 5 – Select VOC BACT for Diesel Storage Tank

VOC BACT for the proposed diesel storage tank is use of submerged filling and light or reflective tank surface colors. Submerged filling will minimize emissions of VOC resulting from splashing of product loaded. A fill pipe opening will be submerged below the tank's liquid surface level, ensuring that liquid turbulence is mitigated during loading, resulting in minimal emissions into the vapor space above the liquid surface. A light-colored or reflective paint for the tank shell and roof will be used to minimize product temperature. Evaporative losses have a strong correlation with temperature of liquid product stored and reducing liquid product temperature can minimize evaporative losses.

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[49] 88 Fed. Reg. 68535 (October 4, 2023)

[50] Preliminary Determination & Statement of Basis – Outer Continental Shelf Air Permit Modification OCS-EPA-R4012-M1 for Statoil Gulf Services, LLC – Desota Canyon Lease Blocks, issued by the U.S. EPA Region 4 on July 9, 2014. Discussion related to BACT analysis for storage tanks, Section 6.5 page 29. https://www.epa.gov/sites/default/files/2015-07/documents/2014_07_09_statoil_pd_0.pdf

[51] While GPC concludes that equipping the proposed diesel storage tank with a floating roof or a closed vent system routed to a control device is technically infeasible insofar as these control options are not applicable, EPA has found these control options to not be cost-effective, even if feasible. In the NSPS Subpart Kc proposal, EPA states that "… cost effectiveness for [volatile organic liquids] with vapor pressures less than the proposed maximum true vapor pressure cutoffs are approximately $10,000 and $11,000 per ton of VOC reduced. This is not cost-effective because it is significantly higher than what the EPA has historically found to be cost-effective for VOC regulations." 88 Fed. Reg. 68541. Considering that distillate oil has a vapor pressure (<0.01 psia) that is significantly less than the lowest vapor pressure cut-off proposed (0.5 psia), the cost of control would be unreasonable on a cost effectiveness basis.

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5.5 Fuel Gas Heater BACT Review

Associated equipment associated with the Project includes:

- Three (3) natural gas-fired fuel gas heaters, each with a heat input rating of less than 10 MMBtu/hr.

5.5.1 Nitrogen Oxides

5.5.1.1 Formation

NO_X formation mechanisms for fuel-burning equipment such as the proposed fuel gas heaters are generally the same as those discussed above for the proposed CT units, although thermal NO_X is expected to be the basis for the majority of NO_X emissions from such heaters.

5.5.1.2 Step 1 – Identify NO_X Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for NO_X emissions from the proposed fuel gas heaters. Generally, NO_X emissions from fuel burning equipment can be controlled through two types of emission control strategies: combustion controls and add-on controls. Combustion controls address thermal NO_X directly by reducing peak flame temperature by, for example, staging combustion and/or recirculating flue gas to reduce the oxygen content of the combustion air. Add-on controls employ various strategies to reduce NO_X emissions to water and nitrogen, which often includes the use of reagents in the presence of a catalyst. Based on the RBLC search results provided in **Appendix E**, Table E-21, no add-on control options were identified. Many facilities listed some variation of use of clean fuels (such as natural gas), good combustion practices (e.g., tune-ups), and combustion controls (such as low or ultra-low NO_X burners), as BACT. Add-on controls potentially applicable to the proposed fuel gas heaters include SCR, selective non-catalytic reduction (SNCR), and non-selective catalytic reduction (NSCR).

5.5.1.3 Step 2 – Eliminate Technically Infeasible NO_X Control Options

Use of Clean Fuels, Good Combustion Practices, and Combustion Controls

Use of natural gas, good combustion practices, and ultra-low NO_X burners are inherent to the Project and technically feasible.

Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR), Non-selective catalytic reduction (NSCR)

As discussed in the BACT analysis for the proposed CT units, SCR, SNCR, and NSCR are all forms of post-combustion add-on controls that reduce NO_X emissions to water and nitrogen, as follows:

- SCR – Injection of nitrogen-based reagent (e.g., ammonia or urea) in the presence of a catalyst
- SNCR – Similar to SCR, except no catalyst is used and higher operating temperatures are required
- NSCR – Catalyst reaction without use of a reagent in exhaust gas with low oxygen content

GPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment similar to the proposed fuel gas heaters. Combustion controls such as low or ultra-low NO_X burners, with or without flue gas recirculation, are the most effective controls that can be obtained through commercial channels for such units. Therefore, add-on controls are not considered available. Additionally, both SNCR and NSCR are not applicable based on the physical and chemical characteristics of the exhaust gas from the proposed fuel gas heaters. For SNCR, the exhaust gas is not hot enough for this add-on control to be effective. For NSCR, the oxygen content of the exhaust gas is too high for this add-on

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control to be effective and the proposed fuel gas heaters cannot be tuned to such low levels of excess air without causing excessive unburned hydrocarbons, soot, smoke, and CO emissions. Accordingly, SCR, SNCR, and NSCR are not technically feasible.

5.5.1.4 Step 3 – Rank Remaining NO_X Control Options

No ranking of control options is required, as use of natural gas, good combustion practices, and ultra-low NO_X burners are the only available and technically feasible control options for NO_X emissions from the proposed fuel gas heaters.

5.5.1.5 Step 4 – Evaluation of NO_X Control Options

The top control options are being proposed for NO_X emissions from the proposed fuel gas heaters. Therefore, no evaluation of the NO_X control options is required.

5.5.1.6 Step 5 – Select NO_X BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters since they are too small to be regulated under NSPS Subpart Dc.

NO_X BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas, good combustion practices, and ultra-low NO_X burners. Based on the RBLC search results, NO_X emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.011 to 0.149 lb/MMBtu.

Based on this information, GPC is proposing a NO_X BACT limit of 9 ppmvd, corrected to 3% O_2, or 0.011 lb/MMBtu, to be demonstrated by monitoring NO_X emissions while emissions of CO are optimized during biennial tune-ups under the Industrial Boiler MACT.[52] Measurements of NO_X (and O_2) will be conducted using the procedures of ASTM D 6522, CTM-030, or EPA reference methods 7E and 3A.

5.5.2 Carbon Monoxide

5.5.2.1 Formation

CO emissions from the proposed fuel gas heaters may result from incomplete conversion of carbon-containing compounds during combustion and are principally influenced by equipment operating conditions.

5.5.2.2 Step 1 – Identify CO Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for CO emissions from the proposed fuel gas heaters. Like NO_X, CO emissions from fuel burning equipment can be controlled through two types of emission control strategies: good combustion practices and add-on controls. For sources such as the proposed fuel gas heaters, there is typically a trade-off between emissions of NO_X and CO. For example, higher combustion temperatures and residence times may lead to more complete fuel combustion and thus lower CO emissions, but these control techniques may result in excessive NO_X emissions. Good combustion practices strive to optimize emissions for both pollutants. Add-on controls may employ various types of catalysts to oxidize CO emissions to CO_2. Based on the RBLC search results provided in **Appendix E**, Table E-22, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such

[52] The proposed NO_X BACT limit, in conjunction with the proposed CO and VOC BACT limits, are based on vendor design information and are equivalent to "state-of-the-art" (SOTA) emission levels for natural gas-fired boiler and process heaters in the state of New Jersey. See State of the Art (SOTA) Manual for Boilers and Process Heaters, State of New Jersey, Department of Environmental Protection, Air Quality Permitting Element, July 1997, last revised February 2004.

as natural gas and good combustion practices (e.g., tune-ups). Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.5.2.3 Steps 2 – Eliminate Technically Infeasible CO Control Options

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

Oxidation Catalyst

Oxidation catalysts are add-on controls which convert emissions of CO to CO_2 in the presence of a catalyst without the addition of any chemical reagent. GPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. As discussed above, only combustion controls for NO_X emissions from small process heaters are commercially available. Therefore, oxidation catalysts not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for CO emissions.

5.5.2.4 Step 3 – Rank Remaining CO Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for CO emissions from the proposed fuel gas heaters.

5.5.2.5 Step 4 – Evaluation of CO Control Options

The top control options are being proposed for CO emissions from the proposed fuel gas heaters. Therefore, no evaluation of the CO control options is required.

5.5.2.6 Step 5 – Select CO BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters since they are too small to be regulated under NSPS Subpart Dc.

CO BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, CO emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.037 to 0.110 lb/MMBtu. As previously mentioned, good combustion practices seek to optimize emissions for both NO_X and CO emissions and only one facility lists fuel gas heaters that have emission limits for both of these pollutants (AL-0329). The CO emission limit for these fuel gas heaters is 0.080 lb/MMBtu, when limited to 0.011 lb/MMBtu for NO_X emissions as proposed above.

Based on this information, GPC is proposing a CO BACT limit of 100 ppmvd, corrected to 3% O_2, or 0.074 lb/MMBtu, to be demonstrated by using a portable analyzer to monitor emissions of CO during biennial tune-ups under the Industrial Boiler MACT.[53] Measurements of CO (and O_2) will be conducted using the procedures of ASTM D 6522, CTM030, or EPA reference methods 10 and 3A.

5.5.3 Volatile Organic Compounds

5.5.3.1 Formation

Like CO, VOC emissions from the proposed fuel gas heaters may result from incomplete combustion of hydrocarbon in fuel and are principally influenced by equipment operating conditions.

[53] *Id.*

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5.5.3.2 Step 1 – Identify VOC Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for VOC emissions from the proposed fuel gas heaters. Like CO, VOC emissions from fuel-burning equipment have similar considerations and can be controlled through good combustion practices and add-on controls. Based on the RBLC search results provided in **Appendix E**, Table E-23, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices. Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.5.3.3 Steps 2 – Eliminate Technically Infeasible VOC Control Options

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

Oxidation Catalyst

Oxidation catalysts are add-on controls which convert emissions of organic compounds to CO_2 in the presence of a catalyst without the addition of any chemical reagent. GPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. Therefore, oxidation catalysts not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for VOC emissions.

5.5.3.4 Step 3 – Rank Remaining VOC Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for VOC emissions from the proposed fuel gas heaters.

5.5.3.5 Step 4 – Evaluation of VOC Control Options

The top control options are being proposed for VOC emissions from the proposed fuel gas heaters. Therefore, no evaluation of the VOC control options is required.

5.5.3.6 Step 5 – Select VOC BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters since they are too small to be regulated under NSPS Subpart Dc.

VOC BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, VOC emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.005 to 0.050 lb/MMBtu and no facilities list a corresponding VOC emission limit for fuel gas heaters limited to 9 ppmvd NO_X and 100 ppmvd CO. Fuel gas heaters under consideration for the Project that can achieve these levels for NO_X and CO emissions are expected to have VOC emissions less than 20 ppmvd.

Vendor information indicates that VOC emissions from the proposed fuel gas heaters should not exceed 20 ppmvd (as methane), corrected to 3% O_2, or 0.010 lb/MMBtu. However, instead of a numerical BACT limit, GPC is proposing the exclusive use of natural gas and optimizing emissions of CO during biennial tune-ups required by the Industrial Boiler MACT as BACT.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

5.5.4 Particulate Matter

5.5.4.1 Formation

PM emissions from fuel-burning equipment such as the proposed fuel gas heaters generally occur in the same manner as those discussed above for the proposed CT units, except that sulfates are expected to have a negligible contribution to the condensable portion of PM.

5.5.4.2 Step 1 – Identify PM Control Options

GPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for PM emissions from the proposed fuel gas heaters. Based on the RBLC search results provided in **Appendix E**, Tables E-24 (PM), 25 (PM_{10}), and 26 ($PM_{2.5}$), no add-on control options were identified. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired fuel-burning equipment like the fuel gas heaters since combustion of natural gas inherently results in low levels of emissions.[54] Instead, many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices as BACT. Accordingly, these control options are the only options considered further.

5.5.4.3 Step 2 – Eliminate Technically Infeasible PM Control Options

Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

5.5.4.4 Step 3 – Rank Remaining PM Control Options

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for PM emissions from the proposed fuel gas heaters.

5.5.4.5 Step 4 – Evaluation of PM Control Options

The top control options are being proposed for PM emissions from the proposed fuel gas heaters. Therefore, no evaluation of the PM control options is required.

5.5.4.6 Step 5 – Select PM BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters since they are too small to be regulated under NSPS Subpart Dc.

PM BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, PM emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.007 to 0.010 lb/MMBtu.

Vendor information indicates that PM emissions from the proposed fuel gas heaters should not exceed 0.007 lb/MMBtu. However, instead of a numerical BACT limit, GPC is proposing exclusive use of natural gas as BACT.

[54] When EPA proposed national standards for small industrial, commercial, and institutional boilers and process heaters in NSPS Subpart Dc, EPA stated that "[b]ecause of [the] low uncontrolled PM emission levels, the application of any type of PM control technology to small natural gas-fired… units would impose significant costs for no benefit. Consequently, the use of any conventional PM control technology to reduce PM emissions from small natural gas-fired… units is considered unreasonable…" 54 Fed. Reg. 24798 (June 9, 1989).

5.5.5 Greenhouse Gases

5.5.5.1 Formation

As with the proposed CT units, GHG emissions that result from the combustion of natural gas in the proposed fuel gas heaters include CO_2, CH_4, and N_2O.

5.5.5.2 Step 1 – Identify GHG Control Options

Based on the RBLC search results provided in **Appendix E**, Table E-27, no add-on control options were identified that would reduce GHG emissions from the proposed fuel gas heaters. Instead, many facilities listed some variation of use of clean fuels (natural gas and distillate oil) and good combustion practices as BACT for GHG emissions.

As explained above, CCS should not be considered as a potentially available control option for sources with insignificant GHG emissions. Accordingly, use of natural gas and good combustion practices are the only potentially available control options for GHG emissions from the proposed fuel gas heaters.

5.5.5.3 Step 2 – Eliminate Technically Infeasible GHG Control Options

Exclusive use of natural gas and good combustion practices for the proposed fuel gas heaters are inherent to the Project and technically feasible.

5.5.5.4 Step 3 – Rank Remaining GHG Control Options

No ranking of control options is required, as the exclusive use of natural gas and good combustion practices are the only available and technically feasible control options for GHG emissions from the proposed fuel gas heaters.

5.5.5.5 Step 4 – Evaluation of GHG Control Options

The top control options are being proposed for emissions of GHG from the proposed fuel gas heaters. Therefore, no evaluation of the control options is required.

5.5.5.6 Steps 5 – Select GHG BACT for Fuel Gas Heaters

No BACT floor exists for emissions from the proposed fuel gas heaters.

GHG BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas as fuel and good combustion practices. GPC is proposing the exclusive use of natural gas and performing biennial tune-ups required by the Industrial Boiler MACT as GHG BACT.

5.6 Summary of Proposed BACT

Table 5-1 summarizes the proposed BACT limits and compliance demonstration methods for each of the Project's proposed emission units.

Table 5-1. Proposed BACT Emission Limits and Compliance Demonstration Methods

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
Each Combustion Turbine	NOx	Natural gas	Clean fuels, DLN combustors, and SCR	2.5 ppmvd NO_X, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Distillate oil	Clean fuels, water injection, and SCR	5.0 ppmvd NO_X, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Both		168.3 tons NO_X or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-mo rolling average
	CO	Natural gas	Clean fuels, good combustion practices and oxidation catalyst	3.5 ppmvd CO, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Distillate oil		5.0 ppmvd CO, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Both		1,004.6 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-mo rolling average
	VOC	Natural gas	Clean fuels, good combustion practices and oxidation catalyst	2.0 ppmvd VOC, corrected to 15% O2	3-run stack test EPA Reference Method 25A
		Distillate oil			
	PM	Natural gas	Clean fuels	0.006 lb/MMBtu, or 24.5 lb/hr	3-run stack test EPA Reference Methods 5 and 202
		Distillate oil		0.014 lb/MMBtu, or 48.5 lb/hr	
	H_2SO_4	Natural gas	Clean fuels	Natural gas, 0.5 grains sulfur/100 scf Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel supplier documentation
		Distillate oil			
	GHG	Both	Clean fuels, efficient design, and good combustion, operating, and maintenance practices	14,483,434 MMBtu and 1,024,830 tons per year CO2e, during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-mo rolling average

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
Emergency Generator	NOx, CO, VOC, PM	Distillate oil	Tier 2 Engine	Comply with NSPS Subpart IIII	Comply with NSPS Subpart IIII
	GHG	Distillate oil	ULSD	Limit operating hour to 200 hr/yr, including 100 hrs/yr for maintenance checks and readiness testing, 50 hr/yr may be used in non-emergency	Comply with NSPS Subpart IIII
Fire Water Engine Pump	NOx, CO, VOC, PM	Distillate oil	Tier 3 Engine	Comply with NSPS Subpart IIII	Comply with NSPS Subpart IIII
	GHG	Distillate oil	ULSD	Limited to 500 hr/yr	Comply with NSPS Subpart IIII
Fuel Oil Storage Tank	VOC	Distillate oil	Submerged fill and light or reflective tank surface colors		Tank design
Each Gas Heater	NOx	Natural gas	Natural gas, good combustion practices, and ultra-low NO_X burners	9 ppmvd, corrected to 3% O_2, or 0.011 lb/MMBtu	Biennial tune-up
	CO	Natural gas	Natural gas, good combustion practices	100 ppmvd, corrected to 3% O_2, or 0.074 lb/MMBtu	Biennial tune-up
	VOC	Natural gas	Natural gas, good combustion practices	20 ppmvd, corrected to 3% O_2, or 0.010 lb/MMBtu	Fuels records
	PM	Natural gas	Natural gas, good combustion practices	0.007 lb/MMBtu	Fuels records
	GHG	Natural gas	Natural gas, good combustion practices	Exclusive use of natural gas	Fuels records

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6. Class II Area Air Quality Modeling Analysis Procedures

This section presents the approach to the dispersion modeling analysis conducted to assess the Project's impacts with respect to applicable state and federal ambient air quality regulations and guidelines. This analysis was conducted in accordance with the EPD PSD Guidance Document (EPD 2017) and US EPA's *Guideline on Air Quality Models* (US EPA 2017) (GAQM), which is contained in 40 CFR Part 51, Appendix W, as well as the modeling protocol submitted on October 11, 2023, and addresses comments on the protocol provided by EPD on November 21, 28, and 30, 2023, and by EPA Region 4 to EPD on November 9, 2023.

The Project is subject to PSD review for NO_X, PM, PM_{10}, $PM_{2.5}$, CO, VOC, H_2SO_4, and GHG. Therefore, associated dispersion modeling analyses were conducted for these pollutants, except for VOC and GHG emissions, as there are no direct modeling requirements for these pollutants. However, the impact of Project VOC emissions as a precursor to ozone is addressed in **Section 6.8**. The modeling analysis also addresses impacts associated with secondary $PM_{2.5}$ as described further in **Section 6.8**.

The EPA has determined that the permitting process can be streamlined without compromising air quality if the EPA and permitting authorities are able to identify a quantitative threshold or dividing line between an insignificant and a significant impact on air quality. Using a quantitative threshold for this purpose is permissible as long as the EPA or the appropriate permitting authority provides a reasoned explanation for why impacts below that value do not cause or contribute to a violation in a particular context.[55] Accordingly, US EPA has defined concentrations, called "significant impact levels" (SILs), that are used as a tool to streamline the evaluation of whether a major new source or modification may cause or contribute to a violation of a NAAQS or exceedance of a PSD increment for any pollutant subject to PSD review. For those pollutants which have modeled concentrations at or below the applicable SIL, that result indicates the Project will not cause or contribute to a NAAQS violation or an exceedance of a PSD increment, so long as the values and their use are justified in the administrative record. In particular, EPA guidance indicates that the SILs may be justified unless an area is currently in violation of the NAAQS, multiple sources may impact the same area, or the permitting authority is aware that a significant portion of the NAAQS or increment has already been consumed.[56] This justification can be provided demonstrating that the difference between background concentrations in a particular area and the NAAQS is greater than the SIL values.[57] On the other hand, if modeling indicated that SILs for some pollutants and averaging periods are exceeded, then a cumulative impact modeling assessment was performed. The results of the cumulative modeling were compared to the NAAQS and PSD increments (see **Table 6-1**), as applicable.

All model input and output files are included with this application submittal to Georgia EPD in the modeling archive contained in **Appendix G**.

Table 6-1. Applicable Significant Impact Levels, PSD Increments, and NAAQS

		Significant Impact Levels (µg/m³)		NAAQS (µg/m³)		PSD Increments (µg/m³)	
Pollutant	Averaging Period	Class I	Class II	Primary Standard	Secondary Standard	Class I	Class II
NO_2	1-hour(1,4)	--	7.5	188	--	--	--

[55] EPA Memorandum, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program, Attachment, at 3 (Apr. 17, 2018) ("EPA SIL Guidance").

[56] EPA SIL Guidance ("[A] permitting authority must also consider whether emissions "contribute" to a violation in circumstances where a violation of the NAAQS is present before considering the proposed increase in emissions from a PSD construction project, or when emissions from multiple sources may impact a particular area.… [T]he use of a SIL may not be appropriate when a substantial portion of any NAAQS or increment is known to be consumed.").

[57] *Id.* at 10.

Pollutant	Averaging Period	Significant Impact Levels (µg/m³)		NAAQS (µg/m³)		PSD Increments (µg/m³)	
		Class I	Class II	Primary Standard	Secondary Standard	Class I	Class II
	Annual(2,5)	0.1	1	100	100	2.5	25
SO_2	1-hour(1,6)	--	7.8	196	--	--	--
	3-hour(3,7)	1.0	25	--	1,300	25	512
	24-hour(3)	0.2	5	--	--	5	91
	Annual(2)	0.1	1	--	--	2	20
PM_{10}	24-hour(3,8)	0.3	5	150	150	8	30
	Annual(2)	0.2	1	--	--	4	17
$PM_{2.5}$	24-hour(3,9)	0.27	1.2	35	35	2	9
	Annual(2,10)	0.05	0.2	12	15	1	4
CO	1-hour(7)	--	2,000	40,000	40,000	--	--
	8-hour(11)	--	500	10,000	10,000	--	--

(1) Interim 1-hour NO_2 and SO_2 SILs set by Georgia EPD

(2) Not to be exceeded (PSD Increment).

(3) Not to be exceeded more than once per year (PSD Increment).

(4) Compliance with the 1-hour standard is demonstrated when the 5-year average of the 98th-percentile (8th high) of the annual distribution of daily maximum 1-hour concentrations is below the standard (NAAQS).

(5) Not to be exceeded (NAAQS).

(6) Compliance with the 1-hour standard is demonstrated when the 5-year average of the 99th-percentile (4th High) of the annual distribution of daily maximum 1-hour average concentrations is below the standard (NAAQS).

(7) Not to be exceeded more than once per year (NAAQS).

(8) Not to be exceeded more than an average of one day per year over three years (NAAQS).

(9) Compliance with the 24-hour standard is demonstrated when the 98th-percentile (8th High) 24-hour concentration at each receptor, based on 5 years of modeling, is predicted below the standard (NAAQS).

(10) Not to be exceeded by the arithmetic average of the annual arithmetic averages from 3 successive years (NAAQS).

(11) Compliance is demonstrated when the 4th highest daily maximum 8-hour average concentration is less than or equal to the standard (NAAQS).

6.1 Modeling Source Approach and Configurations

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) determined to represent the worst-case parameters among the range of possible operating conditions for the proposed Project. The air dispersion modeling analysis was performed considering both normal operations and startup/shutdown of the proposed CT units, which were each modeled as point sources.

6.1.1 CT Units Normal Operations

During normal operations (excluding periods of startup and shutdown), emission rates and stack gas characteristics for the proposed CT units at a given operating load vary as a function of ambient temperature and data was derived for a range of operating conditions as follows:

- 3 operating loads (100%, 75%, and minimum emission compliance (MECL))
- 7 ambient temperatures (105°F, 95°F, 65°F, 59°F, 40°F, 20°F, 0°F)

A summary of the stack data and emission rates for each ambient temperature and operating scenario for each fuel that may be utilized is provided in **Table 6-2** and **Table 6-3**. In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emission rates and stack parameters was used in the

modeling as an initial approach for both fuel options. For each CT unit operating load, the highest pollutant-specific emission rate coupled with the lowest stack gas temperature and flow rate was selected. **Table 6-4** and **Table 6-5** summarize the worst-case emission parameters for each fuel. This data was used to perform a load analysis for the CT units without any additional Project sources, for each fuel, to determine which load resulted in the highest ground-level concentrations. The worst-case load scenario (including startup and shutdown, see **Section 6.1.2**) for each pollutant and averaging period was used in subsequent SIL, NAAQS, and PSD increment modeling, as applicable.

Table 6-2. CT Stack Exhaust Parameters and Emission Rates: Natural Gas Operations

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (ft/s)	Maximum Hourly Emissions (lb/hr) [1][2]			
						NO_x	CO	PM_{10}	$PM_{2.5}$
100% - EC	105	187	37.0	825	89.46	39.0	33.3	23.1	23.1
100% - EC	95	187	37.0	822	89.36	39.0	33.3	23.2	23.2
100% - EC	65	187	37.0	811	89.85	40.0	35.0	23.8	23.8
100% - EC	59	187	37.0	808	89.87	40.0	35.0	24.0	24.0
100%	105	187	37.0	811	***83.68***	35.0	29.8	20.8	20.8
100%	95	187	37.0	813	86.05	37.0	31.5	21.8	21.8
100%	65	187	37.0	809	89.49	40.0	35.0	23.6	23.6
100%	59	187	37.0	807	89.74	40.0	35.0	23.9	23.9
100%	40	187	37.0	806	89.83	41.0	35.0	24.3	24.3
100%	20	187	37.0	800	89.49	***41.0***	***35.0***	***24.5***	***24.5***
100%	0	187	37.0	***795***	87.97	40.0	35.0	24.0	24.0
75%	105	187	37.0	773	***73.47***	29.0	24.5	17.1	17.1
75%	95	187	37.0	769	73.89	29.0	26.3	17.5	17.5
75%	65	187	37.0	757	74.87	31.0	26.3	18.5	18.5
75%	59	187	37.0	753	74.95	31.0	28.0	18.6	18.6
75%	40	187	37.0	752	75.50	32.0	28.0	19.1	19.1
75%	20	187	37.0	***751***	78.08	34.0	29.8	20.0	20.0
75%	0	187	37.0	752	79.38	***35.0***	***29.8***	***20.7***	***20.7***
MECL	105	187	37.0	754	***64.34***	23.0	21.0	13.8	13.8
MECL	95	187	37.0	758	65.44	24.0	21.0	14.1	14.1
MECL	65	187	37.0	744	64.61	24.0	21.0	14.3	14.3
MECL	59	187	37.0	741	64.55	24.0	21.0	14.4	14.4
MECL	40	187	37.0	740	64.85	25.0	21.0	14.7	14.7
MECL	20	187	37.0	***737***	65.61	26.0	22.8	15.2	15.2
MECL	0	187	37.0	738	68.13	***27.0***	***24.5***	***16.3***	***16.3***

Note: Data are provided per emission unit unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions and several ambient temperatures; EC means the stack parameters and emission rates reflect use of evaporative coolers; MECL means minimum emission compliance level.

(2) Hourly emissions reflect operation of a single CT unit firing natural gas only.

(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.

Table 6-3. CT Stack Exhaust Parameters and Emission Rates: Distillate Oil Operations

Load/Scenario[1]	Ambient Temp. (ºF)	Stack Height (ft)	Stack Dia. (ft)	Exit Temp. (ºF)	Exit Velocity (ft/s)	Maximum Hourly Emissions (lb/hr) [2][3]			
						NO_x	CO	PM_{10}	$PM_{2.5}$
100% - EC	105	187	37.0	798	75.54	72.0	44.0	46.24	46.24
100% - EC	95	187	37.0	781	74.65	72.0	44.0	46.38	46.38
100% - EC	65	187	37.0	786	76.20	74.0	45.0	48.08	48.08
100% - EC	59	187	37.0	783	75.58	74.0	45.0	47.94	47.94
100%	105	187	37.0	797	***70.61***	64.0	39.0	42.47	42.47
100%	95	187	37.0	794	72.68	67.0	41.0	44.27	44.27
100%	65	187	37.0	785	75.88	73.0	45.0	47.89	47.89
100%	59	187	37.0	783	76.17	***74.0***	***45.0***	***48.51***	***48.51***
100%	40	187	37.0	781	74.80	74.0	45.0	47.69	47.69
100%	20	187	37.0	779	73.98	74.0	45.0	47.27	47.27
100%	0	187	37.0	***778***	72.83	73.0	45.0	46.37	46.37
75%	105	187	37.0	817	***62.02***	54.0	33.0	34.55	34.55
75%	95	187	37.0	811	62.26	55.0	34.0	34.95	34.95
75%	65	187	37.0	796	63.38	59.0	36.0	36.86	36.86
75%	59	187	37.0	793	63.62	59.0	36.0	37.38	37.38
75%	40	187	37.0	790	64.18	61.0	37.0	38.16	38.16
75%	20	187	37.0	787	65.24	63.0	39.0	39.37	39.37
75%	0	187	37.0	***782***	67.65	***66.0***	***41.0***	***41.70***	***41.70***
MECL	105	187	37.0	825	***57.18***	47.0	29.0	30.24	30.24
MECL	95	187	37.0	820	58.27	49.0	30.0	31.27	31.27
MECL	65	187	37.0	804	59.62	52.0	32.0	33.31	33.31
MECL	59	187	37.0	800	59.68	53.0	32.0	33.67	33.67
MECL	40	187	37.0	798	60.02	54.0	33.0	34.18	34.18
MECL	20	187	37.0	795	60.71	56.0	34.0	35.04	35.04
MECL	0	187	37.0	***793***	61.42	***57.0***	***35.0***	***35.81***	***35.81***

Note: Data are provided per emission unit unless otherwise noted.

(1) Data presented are for multiple operating loads/conditions and several ambient temperatures; EC means the stack parameters and emission rates reflect use of evaporative coolers; MECL means minimum emission compliance level.

(2) Hourly emissions reflect operation of a single CT unit firing fuel oil only.

(3) Bold italicized numbers indicate highest emissions, lowest temperature, and lowest exhaust over the ambient temperatures.

Table 6-4. CT Composite Worst-Case Data(1) Modeling Inputs: Natural Gas Operation

Parameter		Value		
Load (%)		**100%**	**75%**	**MECL**
Stack Height (ft)		187.0	187.0	187.0
Stack Diameter (ft)		37.0	37.0	37.0
Exit Temperature (°F)		795.0	751.0	737.0
Exit Velocity (ft/s)		83.68	73.47	64.34
Pollutant Emissions Per CT Unit (lb/hr)	**PM_{10}**	24.47	20.72	16.31
	$PM_{2.5}$	24.47	20.72	16.31
	NO_X	41.0	35.0	27.0
	CO	35.0	29.8	24.5

Note: Data are provided per emission unit unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the three operating loads taken from Table 6-2 (bold and italicized)

Table 6-5. CT Composite Worst-Case Data(1) Modeling Inputs: Ultra-low Distillate Oil Operations

Parameter		Value		
Load (%)		**100%**	**75%**	**MECL**
Stack Height (ft)		187.0	187.0	187.0
Stack Diameter (ft)		37.0	37.0	37.0
Exit Temperature (°F)		778.0	782.0	793.0
Exit Velocity (ft/s)		70.61	62.02	57.18
Pollutant Emissions Per CT Unit (lb/hr)	**PM_{10}**	48.51	41.70	35.81
	$PM_{2.5}$	48.51	41.70	35.81
	NO_X	74.0	66.0	57.0
	CO	45.0	41.0	35.0

Note: Data are provided per emission unit unless otherwise noted.

(1) The values in the table represent the worst-case stack parameters and the emission rates for the three operating loads taken from Table 6-3 (bold and italicized)

6.1.2 CT Units Startup and Shutdown

In addition to assessing air quality impacts during normal operational, startup and shutdown operations were also included in the modeling for the pollutants that have short-term standards (PM_{10}, $PM_{2.5}$, NO_2, and CO). The vendor data provides estimated duration of startup and shutdown events. Specifically, the data indicates that startup events will last only 32-49 minutes and shutdown events will last only 5-15 minutes depending on the fuel. **Table 6-6** shows a summary of the startup and shutdown duration and lb/event emission totals for each pollutant modeled for each fuel option. The modeling assumes that all three CT units startup simultaneously.

Table 6-6. Summary of Startup and Shutdown Emissions (per Turbine)

Event	Natural Gas (lb/event)			Duration	Ultra-low Distillate Oil (lb/event)			Duration
	NO_X	$PM_{10}/PM_{2.5}$	CO	(Min)	NO_X	$PM_{10}/PM_{2.5}$	CO	(Min)
Startup	168	14	1,270	32	230	97	4,500	49
Shutdown	23	3	430	5	74	70	1,700	15

The modeling for startup/shutdown is comprised of a composite hourly profile of emissions that accounts for a single startup **or** shutdown event per hour. Since each one of these events does not last a full hour, the balance of the hour assumes the CT units are operating at full load. This creates a matrix of four (4) scenarios assessing short-term startup and shutdown emissions. Those scenarios include:

1. Startup natural gas 32 minutes + 100% load natural gas for 28 minutes,
2. Shutdown natural gas 5 minutes + 100% load natural gas for 55 minutes,
3. Startup distillate oil 49 minutes + 100% load distillate oil for 11 minutes, and
4. Shutdown distillate oil 15 minutes + 100% load distillate oil for 45 minutes.

Since the startup/shutdown emissions occur under different stack parameters (compared to normal operations), the modeled hourly profile of emissions includes a startup **or** shutdown event using two co-located stacks. Stack 1 consists of the startup **or** shutdown stack depending on the scenario modeled and uses the total emissions from a single event as input to the model. Stack 2 reflects the normal operating emission rate at 100% load for the balance of the hour that the CT unit is not operating in startup **or** shutdown mode. The modeled emissions for Stack 2 are scaled based on the portion of the hour that the turbine is operating under normal conditions. **Table 6-7** provides the emissions for each scenario modeled for each pollutant.

Stack 1 (startup **or** shutdown stack) stack parameters consist of those shown in **Table 6-4** and **Table 6-5** for the MECL scenario. Stack 2 (normal operations stack) stack parameters consist of those shown in **Table 6-4** and **Table 6-5** for the 100% load scenario.

Each of these four (4) scenarios was included as part of the load analysis described in **Section 7.1**. The hourly profile of emissions was conservatively assumed to be occurring every hour of the year modeled, however, the modeling assumed that there would be only one (1) event per hour. One event is defined as either:

1. 3 CT units start up on natural gas simultaneously and operate at 100% load for the balance of the hour,
2. 3 CT units shut down on natural gas simultaneously and operate at 100% load for the balance of the hour,
3. 3 CT units start up on distillate oil simultaneously and operate at 100% load for the balance of the hour, and
4. 3 CT units shut down on distillate oil simultaneously and operate at 100% load for the balance of the hour.

Table 6-7. Startup/Shutdown Data for the Proposed Simple-Cycle Combustion Turbines

Pollutant	Startup/ Shutdown Duration (min/hour)	Normal Operations Duration (min/hour)	Startup/Shutdown Emissions[1] Stack 1: Total Start (3 CTs) (lbs/ event)	Startup/Shutdown Emissions[1] Stack 1: Modeled Emission Rate Unit8 (lbs/hr)	Startup/Shutdown Emissions[1] Stack 1: Modeled Emission Rate Unit9 (lbs/hr)	Startup/Shutdown Emissions[1] Stack 1: Modeled Emission Rate Unit10 (lbs/hr)	Normal Operation Emissions Stack 2: Max Hourly (lbs/ hr/ CT)	Normal Operation Emissions Stack 2: Modeled Emission Rate Unit8 (lbs/hr)	Normal Operation Emissions Stack 2: Modeled Emission Rate Unit9 (lbs/hr)	Normal Operation Emissions Stack 2: Modeled Emission Rate Unit10 (lbs/hr)
Startup natural gas 32 minutes + 100% load natural gas for 28 minutes										
NO_2	32	28	504.0	168.0	168.0	168.0	41.0	19.1	19.1	19.1
$PM_{10}/PM_{2.5}$	32	28	42.0	14.0	14.0	14.0	24.5	11.4	11.4	11.4
CO	32	28	3810.0	1270.0	1270.0	1270.0	35.0	16.3	16.3	16.3
Shutdown natural gas 5 minutes + 100% load natural gas for 55 minutes										
NO_2	5	55	69.0	23.0	23.0	23.0	41.0	37.6	37.6	37.6
$PM_{10}/PM_{2.5}$	5	55	9.0	3.0	3.0	3.0	24.5	22.4	22.4	22.4
CO	5	55	1290.0	430.0	430.0	430.0	35.0	32.1	32.1	32.1
Startup distillate oil 49 minutes + 100% load distillate oil for 11 minutes										
NO_2	49	11	690.0	230.0	230.0	230.0	74.0	13.6	13.6	13.6
$PM_{10}/PM_{2.5}$	49	11	291.0	97.0	97.0	97.0	48.5	8.9	8.9	8.9
CO	49	11	13500.0	4500.0	4500.0	4500.0	45.0	8.3	8.3	8.3
Shutdown distillate oil 15 minutes + 100% load distillate oil for 45 minutes										
NO_2	15	45	222.0	74.0	74.0	74.0	74.0	55.5	55.5	55.5
$PM_{10}/PM_{2.5}$	15	45	210.0	70.0	70.0	70.0	48.5	36.4	36.4	36.4
CO	15	45	5100.0	1700.0	1700.0	1700.0	45.0	33.8	33.8	33.8

(1) Modeled SUSD assumes that all three turbines are starting up at the same time.

6.1.3 Associated Equipment

The Project will also consist of three natural gas heaters, which were each modeled as point sources. Because the performance data for the heaters is not expected to be affected by ambient conditions, only one set of parameters was modeled (e.g., stack parameters and emission rates associated with maximum capacity). The heaters were modeled conservatively assuming continuous operation throughout the year even though the proposed CT units will comply with a capacity factor limit. **Table 6-8** includes the modeled stack parameters and emission rates for the fuel gas heaters.

The Project will also include an emergency generator and emergency fire water pump engine, which were each modeled as point sources. These units are considered to be intermittent sources and will operate for emergency purposes and for readiness testing, maintenance checks, and other allowed non-emergency purposes. The fire water pump engine is considered an emergency engine and will be operated for no more than 500 hours per year while the emergency generator will be operated for no more than 200 hours per year to comply with Ga. Comp. R & Regs. 391-3-1-.02(2)(mmm). Similar existing sources at Plant Yates typically operate for a total of about 50 hours per year, including emergency and non-emergency operation.

EPD has requested specific information pertaining to the intermittent nature of the emergency generator and emergency fire water pump engine. This information includes:

- Allowable annual emissions from the sources – see **Table 6-8** (additional details on emissions calculations are provided in **Appendix C**, Tables C-6 and C-7).

- Quantification of emissions from these sources – provided in **Appendix C**, Tables C-6 and C-7.
- Frequency of testing and typical hours of testing per year – operation for readiness testing and maintenance checks will occur on a monthly basis, typically for 25-50 hours annually.
- Whether the sources are tested on a routine or non-routine basis – testing will be non-routine insofar as work orders issued to operations and maintenance staff to perform preventative maintenance tasks (e.g., change oil, filter, test engine, etc.) must be completed before the end of a calendar month, but do not specify a specific day or time to complete the task.
- Whether the sources are routinely tested simultaneously – if the work order is issued to the same team member, there is no chance of the sources being testing simultaneously due to their physical separation.

Based on the intermittent and infrequent operation of these units, they were not included in the short-term modeling but were included in annual modeling (see **Table 6-8**).

Table 6-8. Source Parameters and Criteria Pollutant Emission Rates for the Associated Equipment

Emission Source	Stack Height (ft)	Stack Diameter (ft)	Exit Temp. (°F)	Exit Velocity (ft/s)	Emissions (lb/hr/unit)			
					NO_X	CO	PM_{10}	$PM_{2.5}$
Gas Heater (1)	17.0	2.3	700.0	15.0	0.10	0.74	0.075	0.075
Emergency Generator(2)	17.8	1.0	800.0	96.0	1.034	0.123	0.024	0.024
Fire Water Pump(2)	10.0	0.5	900.0	90.0	0.132	0.115	0.006	0.006

Note: Data are provided per emission unit.

(1) Hourly emission rates/calculations based on vendor information. Emission rates presented in this table are preliminary and are subject to change.

(2) Emission rates reflect annualize values based on 200 hours and 500 hours per year of proposed permitted operation for the emergency generator and fire water pump, respectively.

6.2 Model Selection and Options

The suitability of an air quality dispersion model for a particular application is dependent upon several factors. The following selection criteria were evaluated:

- stack height relative to nearby structures;
- dispersion environment;
- representative meteorological data; and
- local terrain.

The US EPA GAQM prescribes a set of approved models for regulatory applications for a wide range of source types and dispersion environments. AERMOD is US EPA's recommended refined dispersion model for simple and complex terrain for receptors within 50 kilometers (km) of a modeled source and is capable of handling the source geometry, terrain, and dispersion environment associated with this Project. Representative meteorological data with suitable data capture for various meteorological parameters is needed to run AERMOD.

Based on a review of the factors described in the following sections, the latest version of AERMOD (version 23132) (US EPA 2023) was used to assess air quality impacts for the proposed Project. AERMOD was used to assess air quality impacts of NO_2, PM_{10}, $PM_{2.5}$, and CO at receptors located within 20 km of the proposed Project site. AERMOD was run with default model options in the CONTROL pathway, unless otherwise noted or discussed with EPD. AERMOD was also applied without using any urban source options as discussed in **Section 6.4**.

6.3 Building Downwash and GEP Height Analysis

US EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from point sources. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" ("GEP") stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of influencing structures, a "default" GEP stack height is creditable up to 65 meters (213 feet) per the *Guideline for Determination of Good Engineering Practice Stack Height* (US EPA, 1985). Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to US EPA's ambient impact criteria.

A GEP stack height analysis was performed for all point sources included in the modeling in accordance with US EPA's guidelines (US EPA, 1985). Per the guidelines, the physical GEP height ("H_{GEP}") is determined from the dimensions of all buildings that are within the region of influence using the following equation:

$$H_{GEP} = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_{GEP}, and

L = lesser dimension (height or projected width) of the structure.

For a squat structure (*i.e.,* height less than projected width), the formula reduces to:

$$H_{GEP} = 2.5H$$

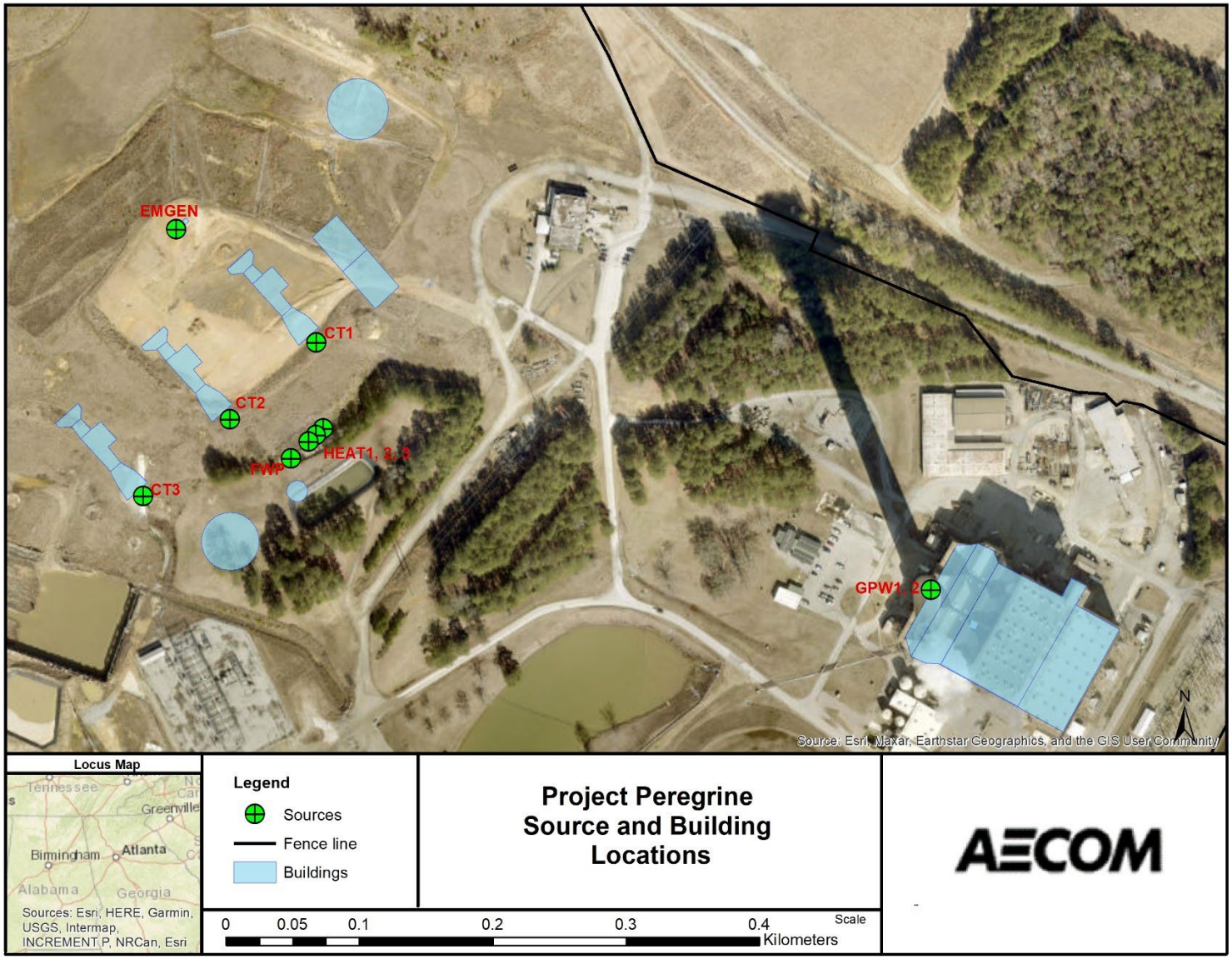
Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. In all instances, the GEP stack height is based on the plane projections of any nearby building which result in the greatest justifiable height. For purposes of the GEP analysis, nearby refers to the "sphere of influence," defined as five times the height or width of the building, whichever is less, downwind from the trailing edge of the structure.

The current Project design has all modeled stacks less than 65 meters. As such, all Project stacks were modeled using their actual stack height. In addition, the EPA's Building Profile Input Program (BPIP-Version 04274) version that is appropriate for use with PRIME algorithms in AERMOD was used to incorporate wind-direction-specific building dimensions for input to AERMOD. Building coordinates and stack locations were developed using site plan drawings, aerial photographs, and GIS software. All relevant new and existing building structures were included in the BPIP modeling for both new and existing stacks at Plant Yates. PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake.

In addition, cumulative modeling required the inclusion of the two existing units (Unit 6 and Unit 7) at Plant Yates, which share a common 805-ft actual stack height. The GEP formula height for the common stack is 495 feet. The controlling structure in determining the GEP formula height is the boiler building, with a height of 198 feet. This structure is wider than it is tall so the GEP formular height is 198 feet times 2.5 = 495 feet. The cumulative modeling was conducted using the GEP stack height of 495 ft for Plant Yates Unit 6 and Unit 7 (model IDs GWP1 and GPW2).

Figure 6-1 provides an illustration of the point sources and buildings used as input to BPIP.

Figure 6-1. Buildings and Sources Included in the BPIP Analysis



6.4 Dispersion Environment

6.4.1 Land Use Analysis

The application of AERMOD requires characterization of the local (within 3 km) dispersion environment as either urban or rural based on prevalent land use. According to US EPA modeling guidelines (US EPA 2017), if more than 50 percent of an area within a 3-km radius of the proposed project is classified as rural, then a rural modeling application is required. Conversely, if more than 50% of the area is urban, an urban dispersion adjustment can be used.

Using the Auer method recommended by the US EPA (US EPA 2017), urban land use types are classified as categories I1, I2, C1, R2, and R3. **Table 6-9** describes these categories and maps them to reasonably equivalent USGS 2016 National Land Cover Database (NLCD) categories. While the Auer method and NLCD do not use the same terms to define their categories, the similarities between the five Auer categories and NLCD categories 23 and 24 are apparent. Thus, it is reasonable to classify NLCD categories 23 and 24 as urban land use. A visual comparison of the 2016 (the most recent version) NCLD land use types to recent aerial imagery from Google™ indicates only insignificant changes to the land use within 3 km since 2016. **Figure 6-2** displays the 2016 NLCD data superimposed over aerial imagery within 3 km of the Plant.

The NLCD data were processed with US EPA's AERSURFACE processor (version 20060) to determine the different land use types within 3 km of the Plant. AERSURFACE is typically used to process NLCD data for input to AERMET, the AERMOD model's meteorological data processor. In this case, AERSURFACE output in the form of the pixel count for each of NLCD's land use types was used to determine the total pixel count of urban land use types within 3 km.

As noted above, urban land use types were assumed to be NLCD categories 23 and 24: "Developed, Medium Intensity" and "Developed, High Intensity", respectively. The pixel count for these categories was 1.83% of the total pixel count for all categories. Thus, a majority (>98%) of the 3 km area around the Plant can be classified as rural land use and AERMOD will not be applied with any urban source options. **Table 6-10** provides the pixel counts as reported in the AERSURFACE output along with respective percentages.

Table 6-9. Comparison of Auer and NLCD Land Use Categories

Auer Urban Land Use Categories[1]			USGS 2016 NLCD Categories[2]	
Type	**Use and Structure**	**Vegetation**	**Category**	**Description**
R2	Dense single/multi-family	< 30%	23	Developed, Medium Intensity – Areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50% to 79% of the total cover. These areas most commonly include single-family housing units.
R3	Multi-family, two story	< 35%	24	Developed, High Intensity – Highly developed areas where people reside or work in high numbers. Examples include apartment complexes, row houses and commercial/industrial. Impervious surfaces account for 80% to 100% of the total cover.
I1	Heavy Industrial	< 5%		
I2	Light/moderate industrial	< 5%		
C1	Commercial	< 15%		

Notes:
[1] US EPA, 2017.
[2] Multi-Resolution Land Characteristics Consortium (MRLC).
https://www.mrlc.gov/data/legends/national-land-cover-database-class-legend-and-description

Table 6-10. AERSURFACE Surface Roughness Output

USGS 2016 NLCD Category	Description	Pixel counts	Percent of Total Pixels
0	Missing, Out-of-Bounds, or Undetermined	0	0.00%
11	Open Water	1,318	4.20%
12	Perennial Ice/Snow	0	0.00%
21	Developed, Open Space	1,196	3.81%
22	Developed, Low Intensity	828	2.64%
23	**Developed, Medium Intensity**	**367**	**1.17%**
24	**Developed, High Intensity**	**209**	**0.67%**
31	Barren Land (Rock/Sand/Clay)	433	1.38%
32	Unconsolidated Shore	0	0.00%
41	Deciduous Forest	9,834	31.31%
42	Evergreen Forest	7,659	24.38%
43	Mixed Forest	1,363	4.34%
51	Dwarf Scrub	0	0.00%
52	Shrub/Scrub	364	1.16%
71	Grasslands/Herbaceous	2,383	7.59%
72	Sedge/Herbaceous	0	0.00%
73	Lichens	0	0.00%
74	Moss	0	0.00%
81	Pasture/Hay	5,208	16.58%
82	Cultivated Crops	0	0.00%
90	Woody Wetlands	236	0.75%
91	Palustrine Forested Wetland	0	0.00%
92	Palustrine Scrub/Shrub Wetland	0	0.00%
93	Estuarine Forested Wetland	0	0.00%
94	Estuarine Scrub/Shrub Wetland	0	0.00%
95	Emergent Herbaceous Wetland	15	0.05%
96	Palustrine Emergent Wetland	0	0.00%
97	Estuarine Emergent Wetland	0	0.00%
98	Palustrine Aquatic Bed	0	0.00%
99	Estuarine Aquatic Bed	0	0.00%
	Total	**31,413**	**100%**

Urban land use types are shown in red, bold text.

Source: AERSURFACE

6.4.2 Terrain

US EPA's GAQM requires that the differences in terrain elevations between the stack base and model receptor locations be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;
- intermediate terrain – locations where the terrain is between the top of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological conditions);
- complex terrain – locations where the terrain is above the plume centerline.

Figure 6-3 provides a topographic map of the area in the vicinity of the proposed Project site. The area near the Plant is characterized as consisting of simple terrain relative to the modeled stacks.

Figure 6-2. NLCD Land Use

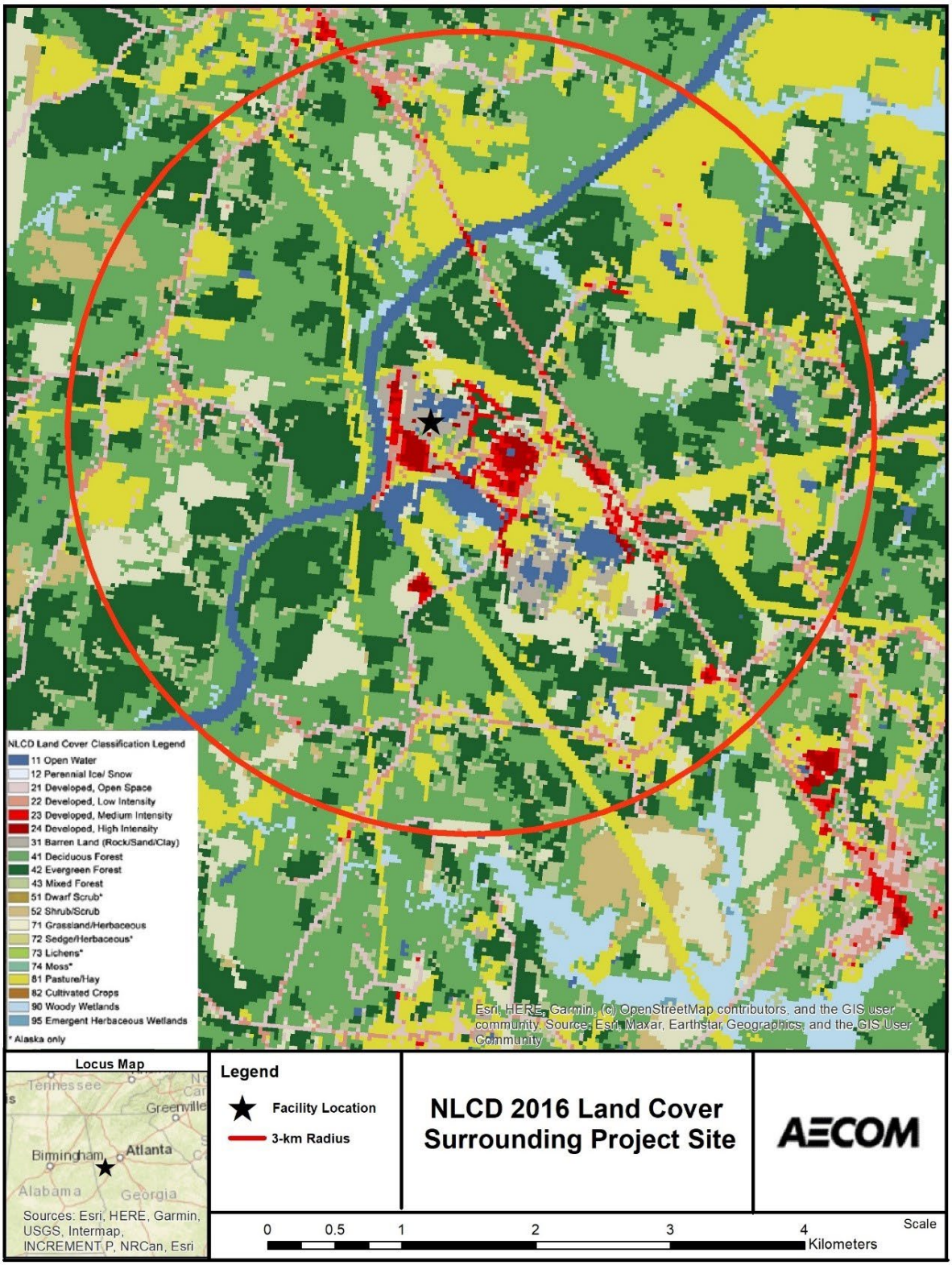
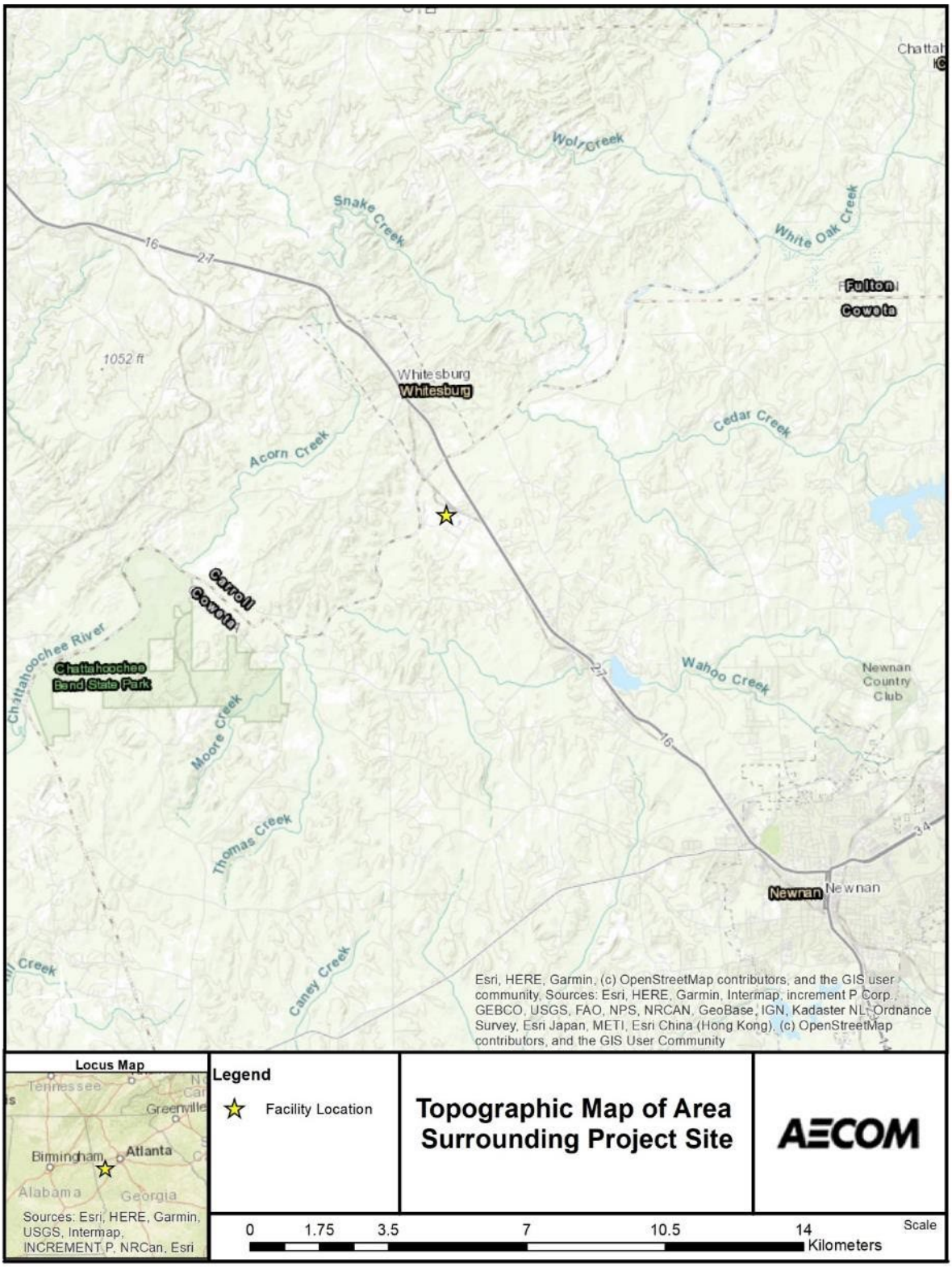


Figure 6-3. Topographic Map of Project Site Area



STF-PIA-10-9 Attachment

6.5 Meteorological Data

The modeling analysis was conducted using 5 years (2017-2021) of surface data from Hartsfield-Jackson Atlanta International Airport (KATL) and upper air meteorological data from Atlanta Regional Airport – Falcon Field (KFFC). Pre-processed meteorological data, processed with the AERMET ADJ_U* option, was obtained from EPD. The Hartsfield-Jackson Atlanta International Airport is located approximately 29 miles northeast of the proposed Project site and was deemed to be the most representative from a meteorological and land use perspective. A wind rose of the airport is presented in **Figure 6-4**.

EPD guidelines, consistent with US EPA's AERMOD Implementation Guide (AIG) (US EPA 2022), specify that the determination of representativeness of meteorological data should include a comparison of surface characteristics; specifically, the surface roughness, albedo, and the Bowen ratio between the monitoring site and the project site. Therefore, a comparison of the surface characteristics in the area surrounding KATL and the Project site was conducted using US EPA's AERSURFACE processor (version 20060).

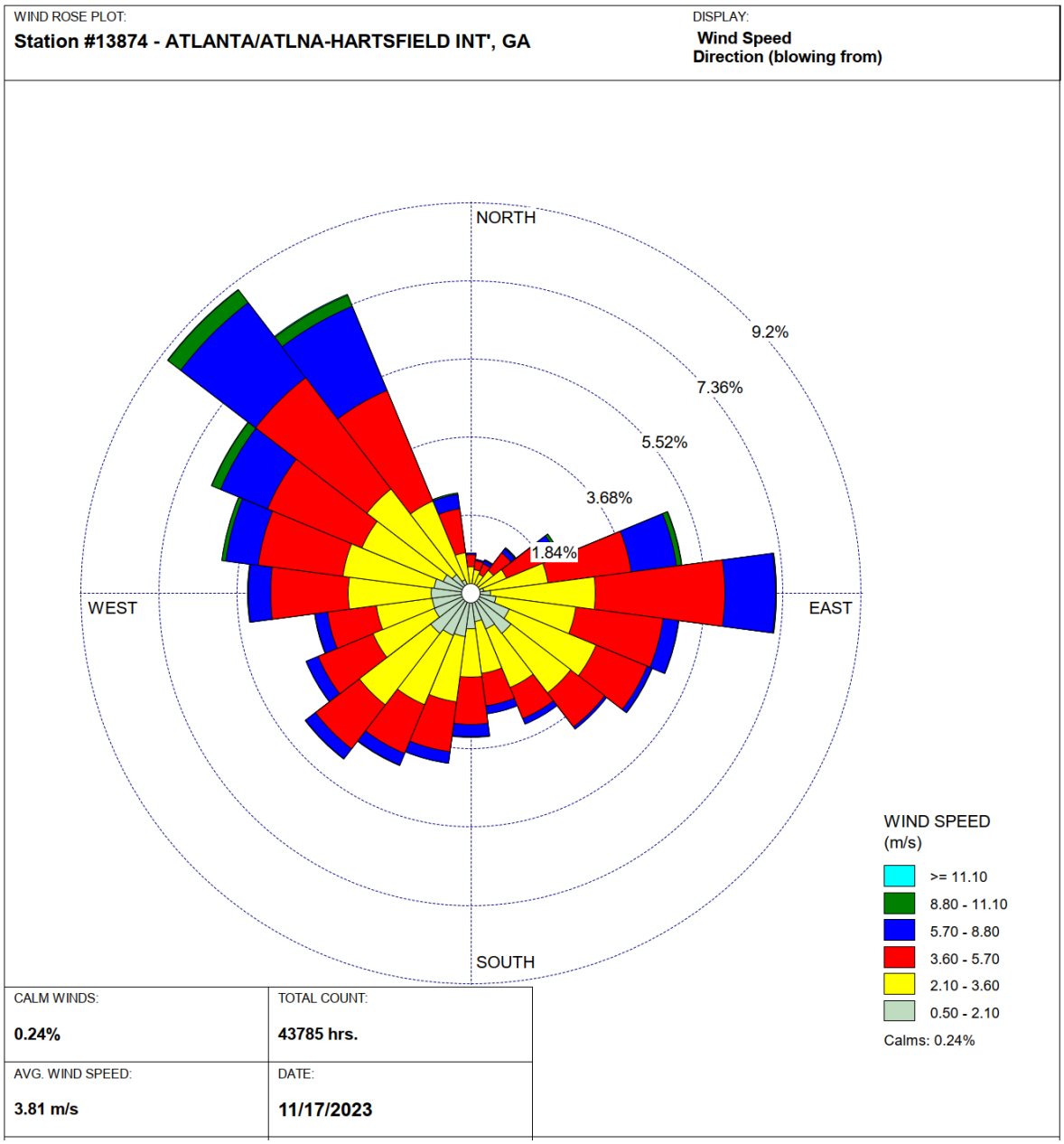
The most recent version of AERSURFACE (20060) uses digital land cover data from the USGS National Land Cover Data 2016 archives and is commonly applied to derive surface land use characteristics for input to AERMET. As such, this tool was utilized to compare the surface characteristics between KATL and the proposed Project site. Specifically, AERSURFACE was applied with a 1-km radius (AERSURFACE default) for the surface roughness determination for each location to determine an annual average set of surface characteristics. The 1-km radius around KATL was partitioned into two site-specific sectors. Sector 1 was classified as non-airport land use and Sector 2 was classified as airport land use. For this analysis, the 1-km radius around the proposed Project site was also split into two sectors, with Sector 1 classified as non-airport and Sector 2 classified as airport for comparison purposes. **Table 6-11** presents the AERSURFACE results for albedo, Bowen ratio, and surface roughness. The AERSURFACE results show that the albedo, Bowen ratio, and surface roughness results are similar, with the largest difference occurring with the Bowen ratio. Because surface roughness is typically the most influential in dispersion modeling, that similarity outweighs the difference in Bowen ratio results. Therefore, the surface characteristics used to process the meteorological data at KATL are representative of the surface characteristics at the proposed Project site, making the meteorological data from KATL acceptable for use in dispersion modeling at the proposed Project site.

Table 6-11. Comparison of Annual Average Land Use Characteristics: Project Site and KATL

Location	Sector (Classification)	Albedo	Bowen Ratio	Surface Roughness (m)
KATL	1 Non-Airport	0.17	0.93	0.056
	2 Airport	0.17	0.93	0.022
Project site	1 Non-Airport	0.15	0.63	0.060
	2 Non-Airport	0.15	0.63	0.086
Absolute Difference Airport – Project site	1 Non-Airport – Non-Airport	0.02	0.30	0.004
	2 Airport – Non-Airport	0.02	0.30	0.064
Relative Difference Airport – Project site	1 Non-Airport – Non-Airport	0.02	0.30	-0.004
	2 Airport – Non-Airport	0.02	0.30	-0.064

Source: AERSURFACE

Figure 6-4. Windrose for KATL



6.6 Receptor Processing with AERMAP

A Cartesian receptor grid extending approximately 20 km from the approximate Plant centroid was used in the modeling. The grid receptors were applied with the following spacing:

- 50 m intervals along the Plant fence line;
- Plant centroid to 3 km spaced at 100-m intervals;
- 3 km to 5 km spaced at 500-m intervals;
- 5 km to 10 km spaced at 1,000-m intervals; and
- 10 km to 20 km spaced at 2,000-m intervals.

STF-PIA-10-9 Attachment

Far-field and near-field views of the receptor grid and ambient air boundary are shown in **Figure 6-5** and **Figure 6-6**, respectively. All maximum model concentrations were resolved to 100-m grid spacing.

Figure 6-6 also shows the ambient air boundary modeled for this proposed Project, which is bounded by an internal access road parallel to a railroad spur to the north, the Chattahoochee River to the west, Dyer Road to the east, and an area designated as no hunting grounds to the south (and east of a transmission right-of-way). GPC owns additional property on all sides of the ambient air boundary, but is only using a portion of the property owned since the river and public roads bisect the property and form a convenient ambient air boundary for purposes of this application. The modeled ambient air boundary consists of security fencing to control public access along the western, northern, and the eastern boundary as depicted in **Figure 6-6**. The ambient air boundary to the south is comprised of other means to control public access, including areas with security cameras, posting of "No Trespassing" signs, security patrolling, and other physical barriers (e.g., densely woody terrain with increasing levels of vegetation toward the river) consistent with US EPA's December 2019 "Revised Policy on Exclusions from Ambient Air"[58]. US EPA December 2019 Guidance states,

> *In setting forth this revised ambient air policy, the EPA is making a limited change to the way it applies the "access" element in the regulatory definition of ambient air. while maintaining the level of public health protection afforded by the original policy. This narrow change is that the EPA will no longer consider a fence or other physical barriers to be the exclusive means by which public access may be effectively precluded for purposes of excluding an area owned or controlled by the source from ambient air under the regulatory definition. Accordingly, the EPA is replacing a concept in the 1980 letter with a broader concept of measures, which may include physical barriers, that are effective in precluding access by the general public. Thus, the EPA's revised ambient air policy, consistent with its discretion available under the regulatory definition of ambient air, is that the atmosphere over land owned or controlled by the stationary source may be excluded from ambient air where the source employs measures, which may include physical barriers, that are effective in precluding access to the land by the general public.*

Additional physical barriers beyond the fencing and other measures to control public access delineated above include extensive property owned by the source operator, active and closed landfills, and forested areas.

AERMAP (version 18081) (US EPA 2018b), the AERMOD terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for the modeled receptors (NAD83 datum and zone 16) using USGS National Elevation Data (NED). The dataset downloaded with Lakes Environmental AERMOD View software consists of 1/3 arc second (~10 m resolution) NED. As per the AERMAP User's Guide (US EPA, 2018b), the AERMAP domain was sufficient to ensure that all significant nodes were included such that all terrain features that exceed a 10% elevation slope from any given receptor were considered. The NED files are referenced to Datum NAD83 (note all source locations and receptors were also referenced to NAD83 UTM Zone 16). The NED files are included in the electronic modeling archive submitted with the final modeling report.

[58] https://www.epa.gov/sites/default/files/2019-12/documents/revised_policy_on_exclusions_from_ambient_air.pdf

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Figure 6-5. Far-field Receptor Grid

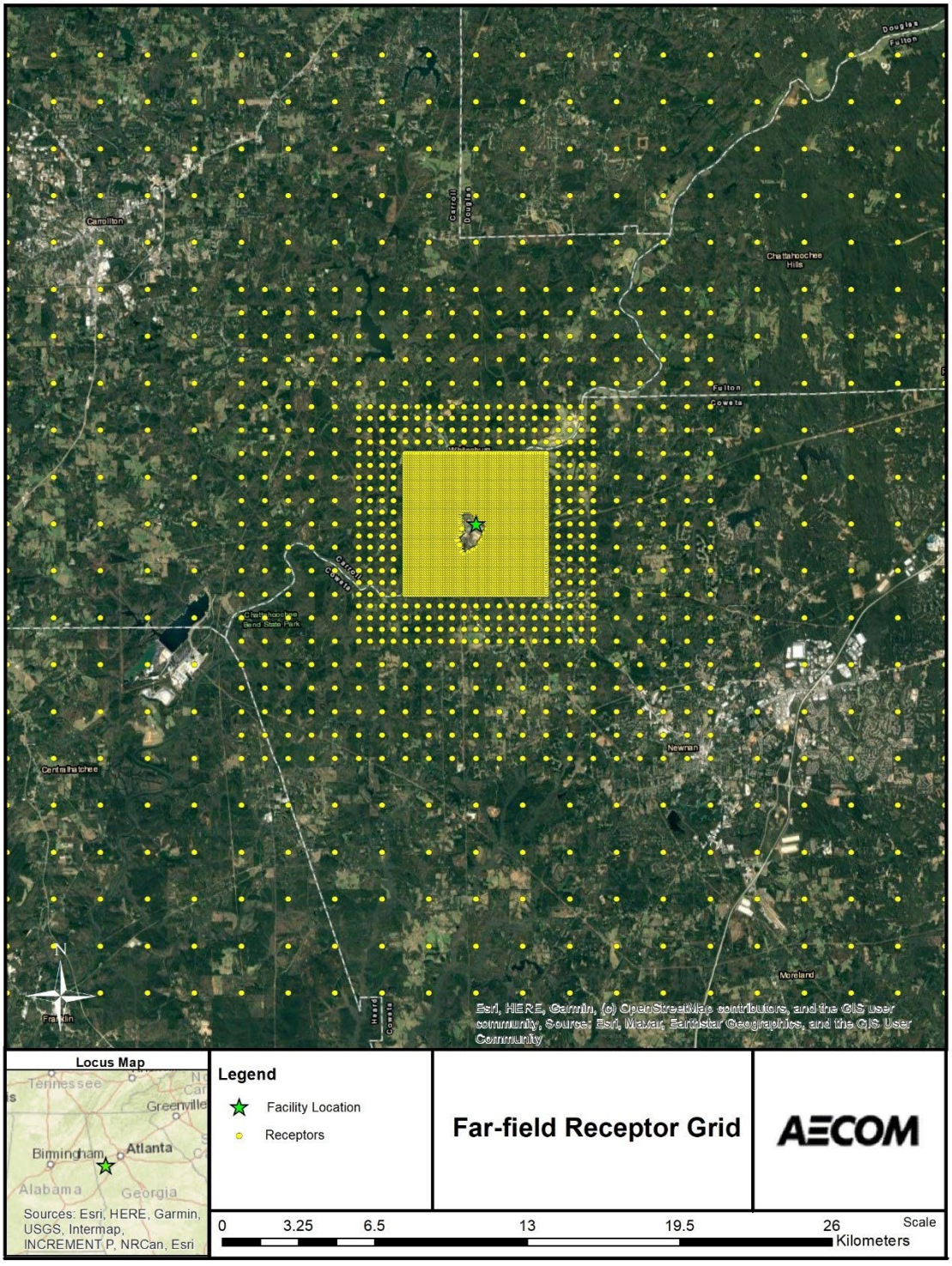
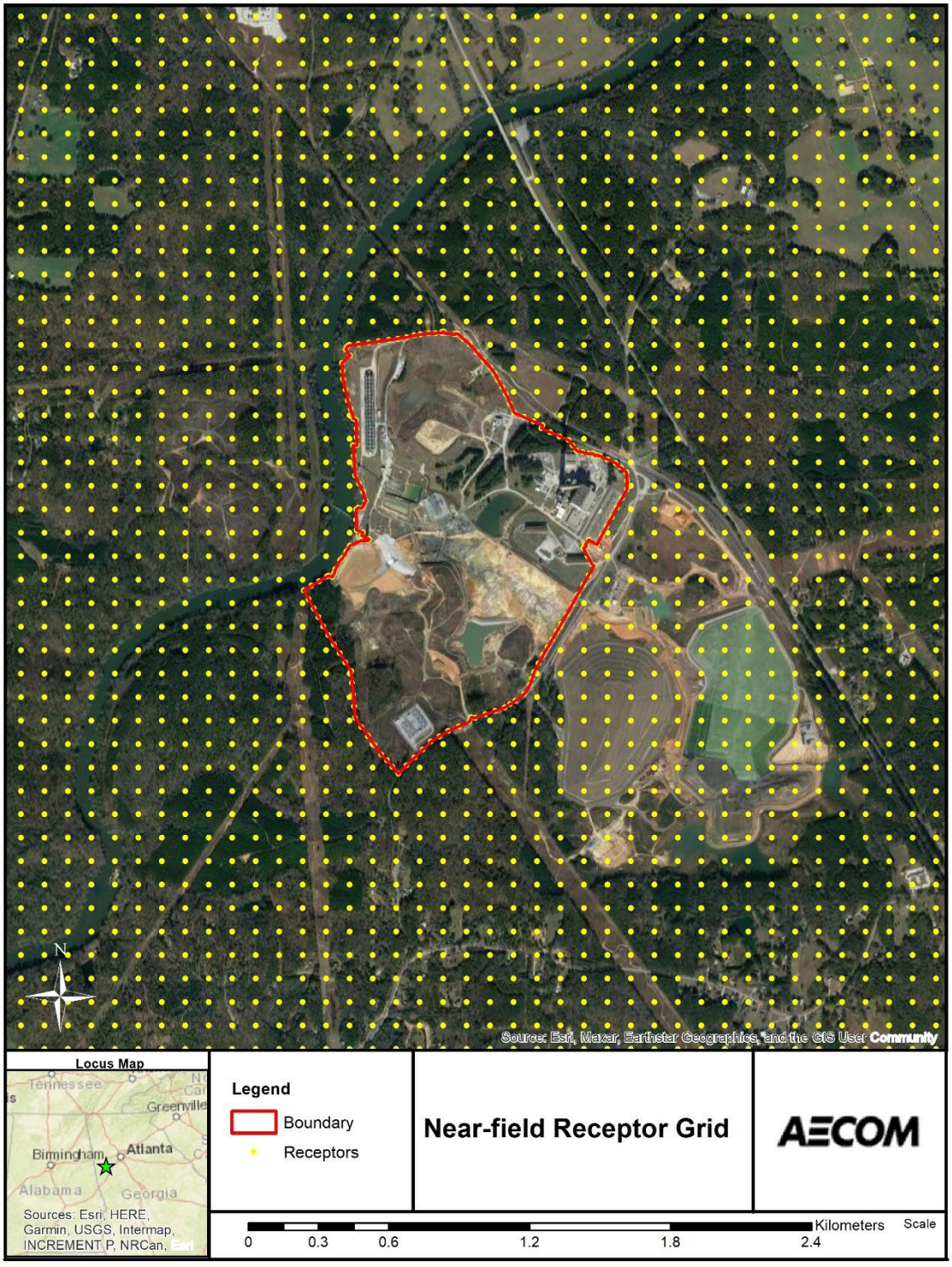


Figure 6-6. Near-field Receptor Grid and Ambient Boundary



STF-PIA-10-9 Attachment

6.7 NO_x Modeling

Based on current US EPA guidance, NO_2 impacts can be determined by using a 3-tiered NO_x-to-NO_2 conversion rate system, where:

- Tier 1 assumes 100 percent conversion of NO_x to NO_2 conversion;
- Tier 2 utilizes the Ambient Ratio Method 2 (ARM2);
- Tier 3 allows the use of refined techniques such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM). Both OLM and PVMRM are default options in AERMOD.

For the Project, modeled concentrations were assessed using the US EPA default Tier 2 ARM2 methodology for estimating NO_2 concentrations from total NO_X emissions.

6.8 Secondary $PM_{2.5}$ and Ozone

In April 2019, US EPA released the final "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program" (EPA-454/R-19-003) (2019 EPA MERPs Guidance) (US EPA 2019). This guidance replaces the draft MERPs Guidance that was released in April 2016. Section 4 of the 2019 EPA MERPs Guidance provides several examples of MERPs Tier 1 demonstrations for sources subject to PSD review. The examples focus on both secondary $PM_{2.5}$ and ozone precursor emissions and at what emission levels those precursors would result in an insignificant impact from a potential project, which would eliminate the need for project-specific modeling. Section 4.1.3 of the 2019 US EPA MERPs Guidance also illustrates how the US EPA-model data used to develop the MERPs could be used as a Tier 1 demonstration tool in a cumulative impact analysis for both $PM_{2.5}$ and ozone. EPD's "Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia" (EPD MERPs Guidance) (EPD 2019) also requires that impacts associated with secondary $PM_{2.5}$ and ozone be addressed in a PSD application, and EPD recommends the use of the MERPs in an analysis.

6.8.1 Approaches

For the Project, precursor emissions for both $PM_{2.5}$ and ozone are shown in **Table 6-12**. Precursor emissions from the Project will be below the MERPs values for the most representative US EPA hypothetical sources, except for NO_X as a precursor to 8-hour ozone. In addition, the Project will have modeled impacts of primary $PM_{2.5}$ that exceed the $PM_{2.5}$ SIL and a cumulative analysis will therefore need to be performed. The methodology described in Section 4.1.3 of the 2019 US EPA MERPs Guidance (which is consistent with EPD's MERPs Guidance) was used to assess the Project and cumulative impacts for $PM_{2.5}$ and ozone.

Table 6-12. Comparison of Project Precursor Emissions with Tallapoosa County, AL MERPs

Pollutant	Precursor Pollutant	Project Emissions (TPY)	Tallapoosa, AL MERP (TPY)
8-hour Ozone	NOx	511.2	327
	VOC	1,046.5	9,709
24-hour PM2.5	NOx	511.2	12,686
	SO2	30.6	2,593
Annual PM2.5	NOx	511.2	116,399
	SO2	30.6	21,106

Source: EPD MERPs Guidance Document

To estimate the Project impact on ozone and secondary $PM_{2.5}$, the list of hypothetical sources that were modeled by US EPA and provided as options in the EPD MERPs Guidance document were considered. There are three hypothetical sources situated on different sides of Georgia, with the Tallapoosa County, AL source being the closest to the Project site by more than 150 km over the Giles County, TN source and more than 200 km over the Allandale County, SC source. Given the closer proximity of the Tallapoosa County site, it was the primary site considered, as it best represents the airshed of the Project source, being located in a similar climate regime and similarly exhibiting a warm and humid climate during the ozone season. For Tallapoosa County, climate summaries from the NWS / NOAA Online Weather products indicate very similar 30-year climate normals when compared to the location of the Project site. A comparison of 30-year (1991-2021) average, maximum, and minimum, temperatures and precipitation for the proposed Project site and the Tallapoosa County hypothetical source is provided in **Table 6-13**. **Table 6-13** shows very similar annual average high temperatures in the low 70s°F, and low temperatures around 50°F, with average low temperatures for Tallapoosa County and the Project site within 1ºF. In addition, mid-summer (peak ozone season) higher temperatures were in the range of 89 – 91°F for both the Project site and Tallapoosa County, and precipitation averages are also close with approximately 55 inches of rain per year each.

In addition, no significant terrain features are present that would differentiate the climate regimes between the Project and the hypothetical source location in Tallapoosa County. Both have similar elevations: 596 ft for Tallapoosa County and 740 ft for the Project site, and both are located in Piedmont area with gently rolling hills. The Tallapoosa County hypothetical source also exhibits similar land use to the Project area. The Project area consists of forested, industrial, and agricultural areas. The Tallapoosa source area consists of forested and agricultural areas. Both are primarily rural. Based on the similarities in land use, climate, and terrain, the data associated with US EPA's hypothetical source in Tallapoosa, AL was used for assessing the impact on ozone and secondary $PM_{2.5}$ for the Project.

Table 6-13. Comparison of 30-Year Climate Normals for Tallapoosa County Hypothetical Source and Project Site (1991 – 2021)

Station/ Source	Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Ann
Tallapoosa Co. Alabama	Average Max. Temperature (°F)	55.8	59.8	67.9	75.1	82.1	87.9	91.0	90.0	85.5	76.5	66.2	58.4	74.5
	Average Min. Temperature (°F)	32.4	35.4	41.8	48.6	58.1	66.3	69.9	68.9	62.9	51.0	40.5	35.3	50.7
	Average Total Precipitation (in.)	5.76	5.40	5.65	4.65	4.48	4.81	5.38	4.69	3.63	2.94	4.40	5.53	57.0
Project Site	Average Max. Temperature (°F)	52.9	57.3	65.2	73.3	80.4	86.0	88.6	87.3	82.2	72.8	62.8	55.2	72.0
	Average Min. Temperature (°F)	32.0	34.5	40.7	47.5	56.7	64.6	68.8	67.9	61.4	49.8	39.0	34.5	49.8
	Average Total Precipitation (in.)	5.11	5.26	5.52	4.54	3.89	4.19	4.94	3.92	4.10	3.60	4.38	5.06	55.1

Source: NOAA Online Weather Data, https://weather.gov

6.8.2 Analyses

Secondary $PM_{2.5}$

The analysis for secondary $PM_{2.5}$ was based on EPD's MERPs Guidance (Equation 6) values for Tallapoosa County. Of importance in this equation (see red box) are the Project-specific secondary $PM_{2.5}$ concentrations, which are based on the relationship of precursor NO_X and SO_2 emissions with the specific MERPs values for the Tallapoosa County source. The secondary $PM_{2.5}$ concentrations were added to the Project direct modeled $PM_{2.5}$ (using AERMOD) to estimate total Project concentrations. The Project secondary $PM_{2.5}$ concentrations are calculated in **Table 6-14**. These concentrations are added to modeled AERMOD concentrations for comparison with the NAAQS and PSD increments as applicable for $PM_{2.5}$.

$$Background_PM2.5 + MDV_PM2.5 + \left(\frac{FEMIS_SO2}{MERP_SO2} + \frac{FEMIS_NOx}{MERP_NOx}\right) * SIL_PM2.5 \leq NAAQS_PM2.5$$

Table 6-14. Proposed Project Estimated Secondary $PM_{2.5}$ Concentrations

Averaging Period	NO_X		SO_2		Project Estimated Secondary $PM_{2.5}$ Concentration ($\mu g/m^3$)
	EPA MERP (TPY)	Project Precursor Emissions (TPY)	EPA MERP (TPY)	Project Precursor Emissions (TPY)	
24-hr $PM_{2.5}$	12,686	511.2	2,593	30.6	0.063
Annual $PM_{2.5}$	116,399	511.2	21,106	30.6	0.001

Ozone

For ozone precursors (NO_X and VOC), a similar approach was used as outlined in EPD's MERPs Guidance (Equation 5) for values for Tallapoosa County. Of importance in this equation (see red box) is the Project-specific ozone concentration, which is based on the relationship of precursor NO_X and VOC emissions with the specific MERPs values for the Tallapoosa County source. The Project ozone concentration is calculated in **Table 6-15**. This concentration was added to the monitored design concentration in accordance with EPD guidance to estimate the total ozone concentration that was then compared to the NAAQS.

$$Background_ozone + \left(\frac{FEMIS_NOx}{MERP_NOx} + \frac{FEMIS_VOC}{MERP_VOC}\right) * SIL_ozone \leq NAAQS_ozone$$

Table 6-15. Project Estimated Ozone Concentrations

Averaging Period	NO_X		VOC		Project Estimated Ozone Concentration ($\mu g/m^3$)
	EPA MERP (TPY)	Project Precursor Emissions (TPY)	EPA MERP (TPY)	Project Precursor Emissions (TPY)	
8-hour Ozone	327	511.2	9,709	1045.8	1.7

The closest and most representative ambient air quality monitor to the Project is the state-operated Newnan monitor. However, since this monitor has been shut down and the latest available design concentrations are from 2015-2017, the next closest most representative monitor, Douglasville, was chosen. The applicable ozone data from this monitor is summarized in

Table 6-16. The Douglasville ozone monitor is located approximately 21 miles north-northeast of the proposed Project in an area that is surrounded by forested and industrial areas. The proposed Project is also located in a rural area and most of the surrounding land use is forested, industrial, or used for agriculture with some small residential areas. The three year (2020-2022) 8-hour ozone NAAQS design value for Douglasville is 63 ppb as provided in the Georgia EPD's Background Data spreadsheet.[59] Adding the proposed Project ozone concentration of 1.7 ppb to the 63 ppb results in a total concentration of 64.7 ppb, which is below the NAAQS of 70 ppb.

This approach is conservative for the following reasons:

- The Project-modeled value being derived from the MERP data is a highest modeled concentration, not the highest 4th high consistent with the standard.
- This approach assumes that the highest Project-modeled concentration derived using the MERP data occurs on the same days in which the monitor's highest design concentration occurred, which is a conservative paired-in time assumption.
- The Tier 1 approach also assumes that the location of the peak concentration prediction coincides with the peak background ozone concentration.

Table 6-16. 8-Hour Ozone Design Values for 2020 – 2022

State-Operated Ozone Monitor Name	Monitor County	Monitor AIRS ID	Design Concentration (2020-2022) (ppb)
Douglasville	Douglas	130970004	63

Source: https://epd.georgia.gov/georgia-background-data

6.9 Background Air Quality and Pre-Construction Monitoring

6.9.1 Available Representative Ambient Air Quality Data

Ambient air quality data are used to represent the contribution to total ambient air concentrations from non-modeled sources. The objective of reviewing this data is to develop representative background concentrations which, when added to modeled impacts, are used in the NAAQS analysis. This section summarizes the ambient background concentrations used in the NAAQS analysis. The monitored concentrations presented in this section were obtained from values provided by EPD.[60] While EPD's website identifies a set of "Statewide" default concentrations for NO_2 and $PM_{2.5}$, the other locations provided on EPD's website were also considered to determine the most representative monitors for the proposed Project location.

6.9.2 NO_2 Background Monitor Selection

The monitors for NO_2 background concentrations are as follows: Yorkville (AQS ID: 13-223-0003), South DeKalb (AQS ID: 13-089-0002, near Decatur), NR-GA Tech (AQS ID: 13-121-0056, near Georgia Tech/Atlanta), and NR-285 (AQS ID: 13-089-0003, near Interstate 285 in the Atlanta-Sandy Springs-Marietta corridor). The NR-285 monitor is specifically situated to track NO_2 concentrations associated with interstate traffic and is not representative of the Project site. The NR-GA Tech and South DeKalb monitors are also located in the Atlanta Metro region, approximately 55 and 65 km away, respectively, with higher population densities (see **Table 6-17**) and more urban characteristics than the Project site's rural location. The Yorkville

[60] https://epd.georgia.gov/georgia-background-data

monitor is the closest of the four, around 50 km from the proposed Project site, and is situated in a rural area with population densities (see **Table 6-17**) similar to the proposed Project site.

EPD considers the Yorkville monitor (located in Paulding County) to be a representative background NO_2 monitor for areas that either do not have any large nearby NO_2 sources or for which all large nearby NO_2 sources are accounted for in the offsite emissions inventory, which describes the Project's airshed well. However, the Yorkville NO_2 monitor ceased operation in 2015. Therefore, an analysis was performed to justify the use of this older dataset versus using more recent data from a less representative airshed.

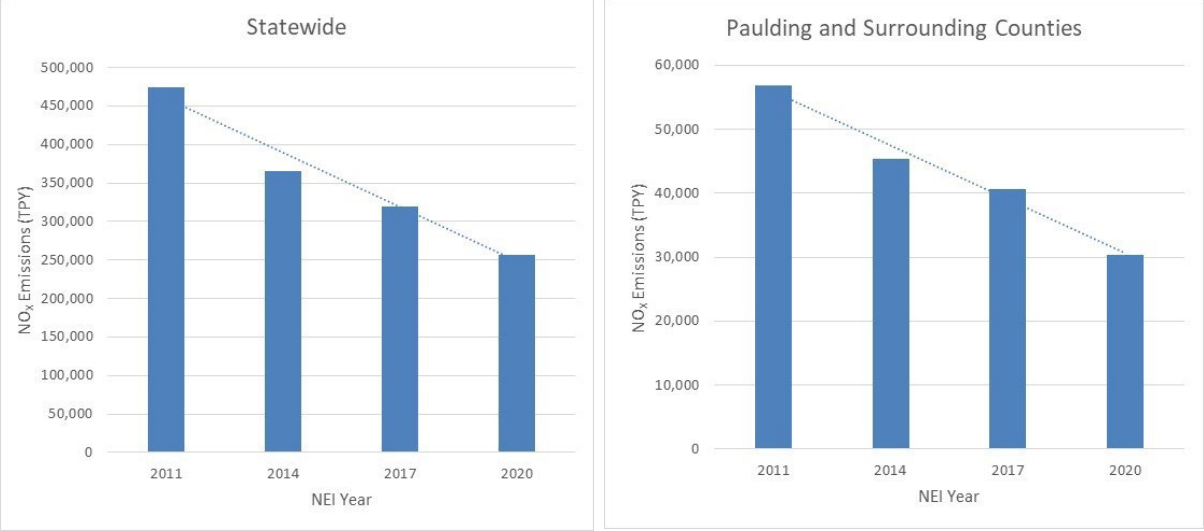
To make this justification, an analysis was performed to compare nearby NO_X emissions trends with Yorkville monitor trends leading up to the shutdown of that monitor. As shown in **Figure 6-7**, NO_X emissions in the state and Paulding (plus surrounding) counties show downward trends between 2011 and 2020. **Figure 6-8** also shows a downward trend in monitored NO_2 concentrations values. This downward trend in county/state level emissions and measured concentrations at the Yorkville monitor suggests that had the monitor continued to operate after 2015, the measured NO_2 concentrations would either have remained stable or would have decreased over time. Given these factors, the Yorkville monitor is most representative of the proposed Project site for NO_2. **Table 6-18** provides ambient background concentrations from EPD for the Yorkville monitor that was relied upon in the NAAQS modeling.

Table 6-17. Population Data for Background Monitors

Monitors and Project Site	County	County Population	Population per Square Mile
Project Site	**Coweta**	**146,158**	**331.4**
Yorkville	Paulding	168,661	540.0
Atlanta	Fulton	1,066,710	2,025.3
South DeKalb/Decatur	DeKalb	764,382	2,854.9
Ashland, AL	Clay	14,236	23.6

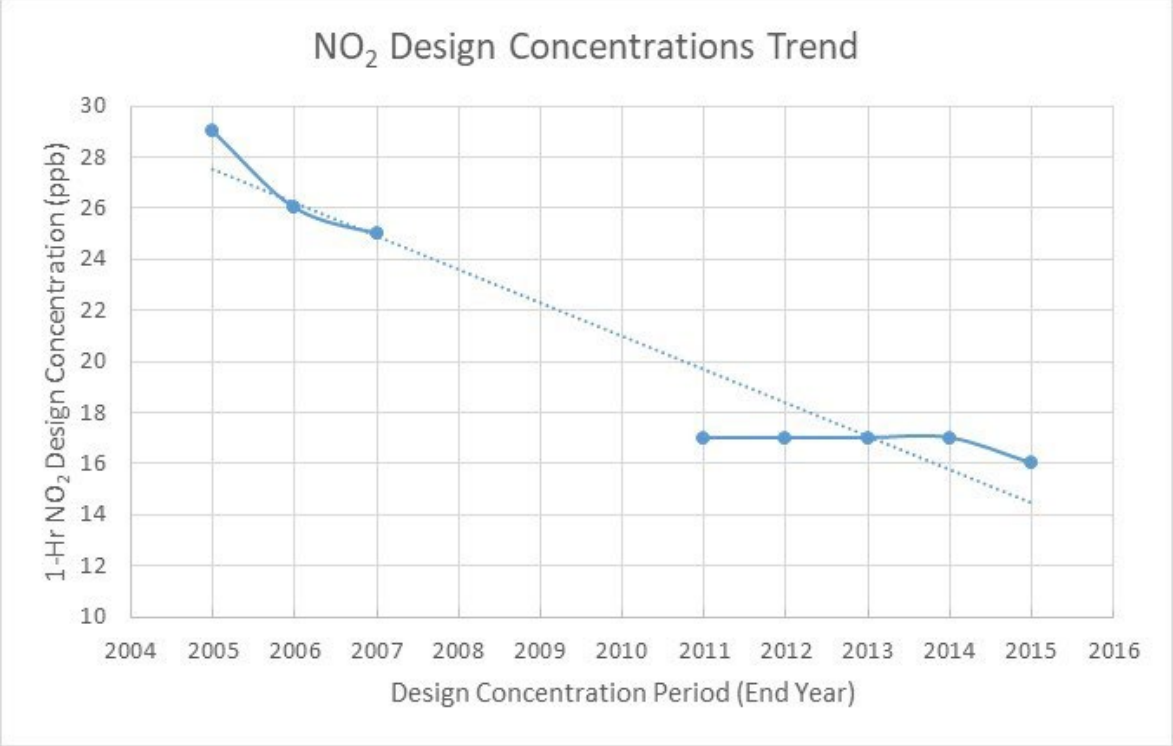
Source: US 2020 Census data from https:census.gov/quickfacts

Figure 6-7. NO_X Emissions Trends from National Emission Inventory Data[61]



[61] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

Figure 6-8. NO_2 Concentration Trend for the Yorkville Monitor



6.9.3 $PM_{2.5}$ Background Monitor Selection

The closest monitors for $PM_{2.5}$ background concentrations are as follows: Yorkville (AQS ID: 13-223-0003) and Ashland, AL (AQS ID: 01-027-0001). These rurally located monitors better represent the Project site from a population density (see **Table 6-17**) and land use perspective as compared to other monitors located in the Atlanta metro area. While either could serve as a representative monitor, the Ashland monitor is almost double the distance of the Yorkville monitor from the proposed Project site and is located in an area with a lower population density. As such, the Yorkville monitor is the most representative of the Project site from a population density perspective.

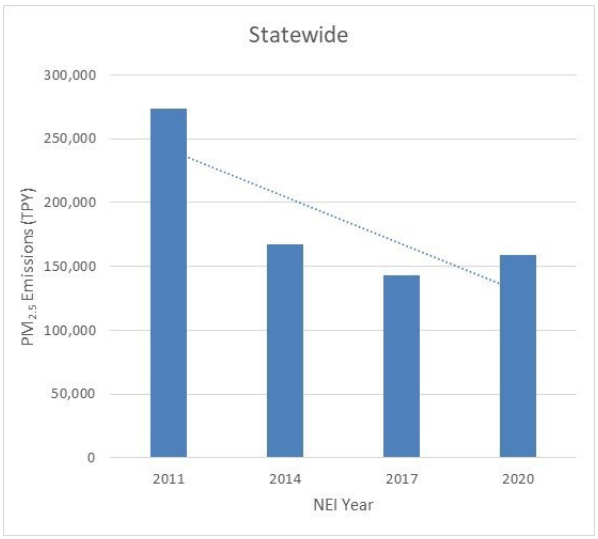
Similar to NO_2, EPD considers the Yorkville monitor (located in Paulding County) to be a representative background $PM_{2.5}$ monitor for areas that either do not have any large nearby $PM_{2.5}$ sources or for which all large nearby $PM_{2.5}$ sources are accounted for in the offsite emissions inventory, which describes well the Project's airshed. The Yorkville $PM_{2.5}$ monitor ceased operation in 2016. Therefore, an analysis was also performed to justify the use of this older dataset for $PM_{2.5}$ versus using more recent data from a less representative monitor.

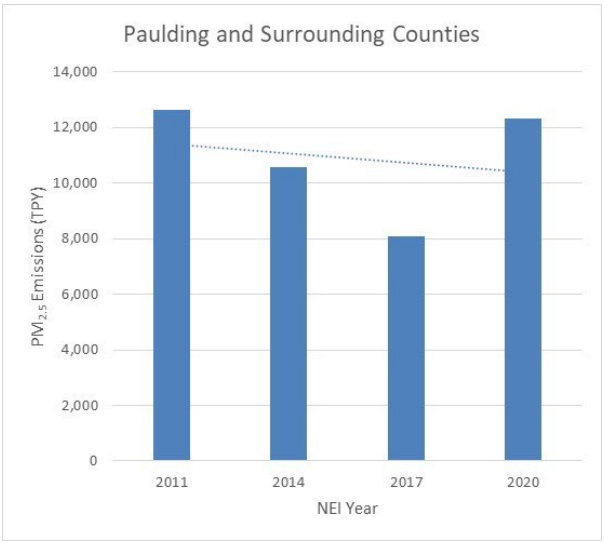
To make this justification, similar to the analysis performed for NO_X, an analysis was performed to compare nearby emission trends of $PM_{2.5}$ (along with SO_2 as a precursor to secondary $PM_{2.5}$) with Yorkville monitor trends leading up to the shutdown of that monitor. As shown in **Figure 6-9**, $PM_{2.5}$ and SO_2 emissions in the state and Paulding (plus surrounding) counties show downward trends between 2011 and 2020. There is a notable reduction in SO_2 emissions, which is likely a large contributor to the overall decrease in $PM_{2.5}$. **Figure 6-10** also shows a downward trend in monitored $PM_{2.5}$ concentrations values from 2005-2016. This downward trend in county/state level emissions and measured concentrations at the Yorkville monitor suggests that had the monitor continued to operate after 2016, the measured $PM_{2.5}$ concentrations would either have remained

stable or would have decreased over time. Given these factors, the Yorkville monitor is most representative of the Project site for $PM_{2.5}$.

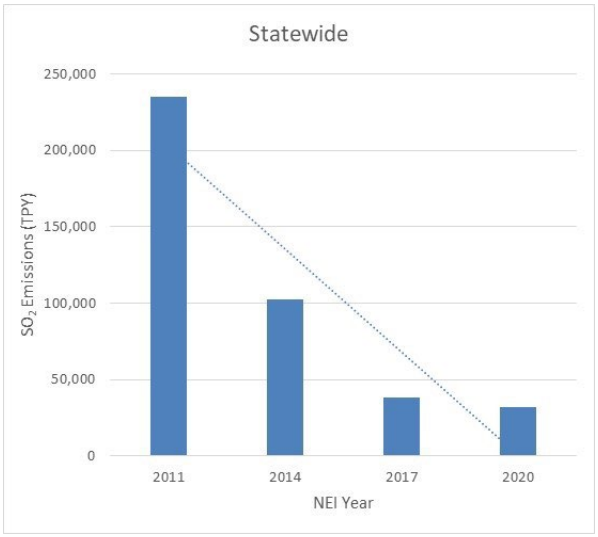
Figure 6-9. $PM_{2.5}$ and SO_2 Emissions Trends from National Emission Inventory Data[62]

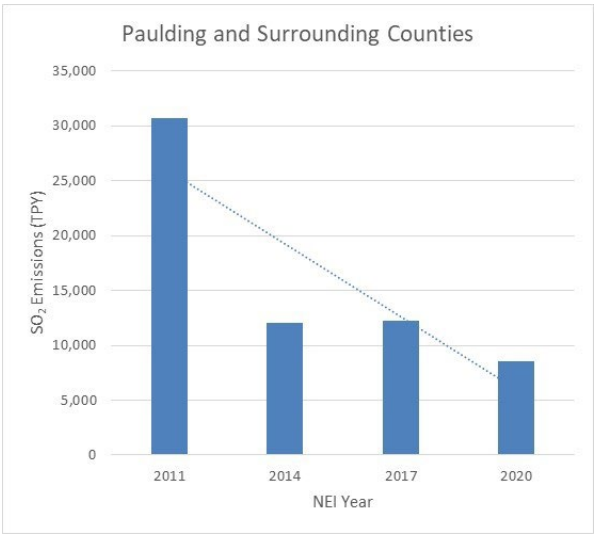
$PM_{2.5}$ NEI Emissions Data





SO_2 NEI Emissions Data





[62] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

Figure 6-10. $PM_{2.5}$ Concentration Trend for the Yorkville Monitor

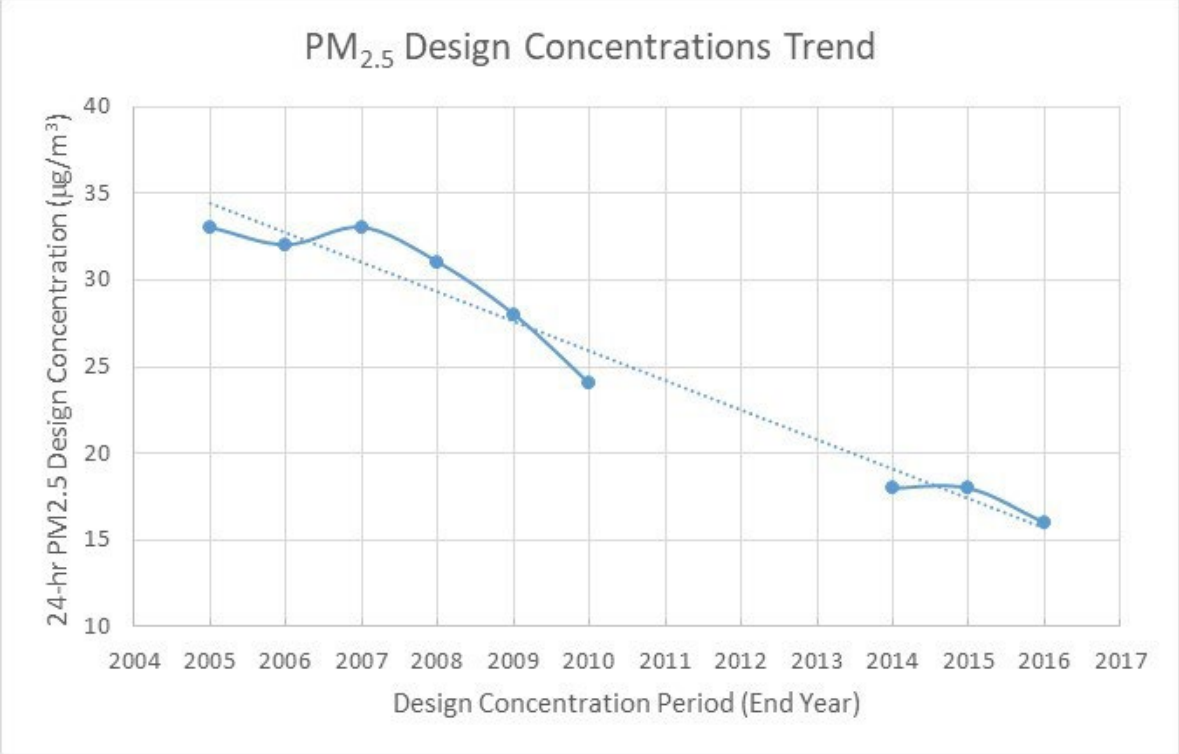


Table 6-18 provides ambient background concentrations from EPD for the Yorkville monitor that was relied upon in the NAAQS modeling.

Table 6-18. Ambient Background Concentrations for NAAQS Modeling

Pollutant	Averaging Period	Design Concentration (µg/m³)
NO_2	1-hour	30.3
$PM_{2.5}$	24-hour	16.2

Source: Georgia EPD

6.9.4 Pre-construction Monitoring

According to 40 CFR §52.21(m), an analysis of ambient air quality in the vicinity of the proposed Project for each pollutant subject to PSD review must be conducted. Air quality data are obtained from pre-construction monitoring or, under certain conditions, from existing monitoring data. Existing air quality monitoring data may be used in lieu of pre-constructing monitoring if:

- The data are representative of the proposed facility's impact areas;
- The data are of similar quality as would be obtained if the applicant monitored according to the PSD requirements; and
- The data are current; that is, the data have been collected during the two-year period preceding the permit application, provided the data are still representative of current conditions.

Existing ambient monitoring data from EPD's monitoring network was used to satisfy the requirement for pre-construction monitoring, as described in previous sections.

7. Class II Area Significant Impact Level Analysis Results

7.1 Load Analysis

Prior to performing the Class II Area SIL analysis, a load analysis for the three CT units was performed to determine the worst-case operating load (normal operations, startup, or shutdown) in terms of ground-level concentrations. This analysis was performed using data in **Table 6-4**, **Table 6-5**, and **Table 6-6** along with normalized emission rates assuming 90% conversion of NO_X to NO_2 (Tier 1 Option). Model results were estimated for each applicable averaging period, including 1-hour, 3-hour, 8-hour, 24-hour, and annual.

The normalized concentrations associated with the load analysis run were used to calculate pollutant and averaging period-specific concentrations to determine which resulted in the highest modeled concentration. This modeling analysis was performed with AERMOD and the associated databases as described in **Section 6**.

The results of the load analysis are shown in **Table 7-1**. **Table 7-1** shows the worst-case turbine operating load for short-term averaging periods (1-hour, 3-hour, 8-hour, and 24-hour) is startup on distillate oil. For the annual averaging period, the highest modeled concentration results from firing distillate oil including startup and shutdown operations. These load conditions were used to complete the SIL modeling analyses presented in **Section 7.2**.

Table 7-1. Load Analysis Results (Maximum Modeled Concentration per Averaging Period (µg/m³))

Turbine Load	1-hr NO_2(1)	Ann NO_2(1)	1-hr CO	8-hr CO	24-hr $PM_{2.5}$	Ann $PM_{2.5}$	24-hr PM_{10}	Ann PM_{10}
Natural Gas Scenarios								
100%	2.658	0.011	2.521	1.020	0.278	0.007	0.278	0.007
75%	2.495	0.012	2.358	1.068	0.294	0.008	0.294	0.008
MECL	2.164	0.011	2.184	1.082	0.288	0.007	0.288	0.007
100% with Startup	14.707	--	114.291	56.496	0.376	--	0.376	--
100% with Shutdown	4.280	--	40.610	19.902	0.307	--	0.307	--
Annual (with SUSD)	--	0.017	--	--	--	0.008	--	0.008
Distillate oil Scenarios								
100%	5.349	0.025	3.614	1.679	0.721	0.018	0.721	0.018
75%	5.342	0.026	3.687	1.868	0.756	0.018	0.756	0.018
MECL	4.918	0.025	3.355	1.785	0.728	0.017	0.728	0.017
100% with Startup	**20.825**	--	**432.063**	**229.860**	**2.105**	--	**2.105**	--
100% with Shutdown	10.396	--	165.684	87.979	1.964	--	1.964	--
Annual (with SUSD)	--	**0.035**	--	--	--	**0.023**	--	**0.023**

(1) Assumes 90% conversion of NO_x to NO_2
(2) Bold type indicates the worst-case operating load by pollutant and averaging period.

7.2 SIL Analysis

The Class II Area SIL analysis was conducted using AERMOD for the worst-case operating load on a pollutant and averaging period-specific basis (as determined in **Section 7.1**). In addition to the worst-case operating load for the proposed CT units, the SIL analysis also includes the fuel gas heaters for the short-term modeling, and fuel gas heaters, emergency generator, and fire pump for the annual modeling.

The SIL modeling analysis was used as a tool in evaluating whether the emissions of NO_2, CO, PM_{10}, and $PM_{2.5}$ from the Project may cause or contribute to a NAAQS or increment exceedance. The evaluation was made using the highest short-term and highest annual modeled concentration over the five years of meteorological data modeled. For 1-hour NO_2, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$, impacts were determined based on the highest 5-year average concentrations. Additionally, the modeled NO_2 concentrations were assessed using the EPA default Tier 2 ARM2 methodology for estimating NO_2 concentrations from total modeled NO_X emissions.

EPA guidance[63] indicates that use of the SILs may be justified provided that the difference between ambient background concentrations representative of the Project area and the NAAQS is greater than the SIL values. For the Project, all NO_2, CO, PM_{10}, and $PM_{2.5}$ monitors in the State of Georgia were evaluated and show that the difference between the monitored design values and the NAAQS is greater than the SIL values, thus justifying the use of the SILs.

Since the SIL values developed by EPA are justified for use in this case, no further modeling is needed to satisfy the required "cause or contribute" determination for those pollutants and averaging periods with modeled concentrations less than the SILs. For those pollutants and averaging periods with modeled concentrations that exceed the relevant SIL, a Class II Area cumulative impact analysis was performed to evaluate whether the Project may cause or contribute to an exceedance of the NAAQS or PSD increments. For $PM_{2.5}$, the secondary $PM_{2.5}$ concentrations estimated as described in **Section 6.9** were added to modeled concentrations for comparison with the SILs.

A comparison of the overall maximum modeled concentrations with the SILs is presented in **Table 7-2** for the worst-case operating load. As is depicted in **Table 7-2**, all modeled concentrations are below their respective SILs with the exception of 1-hour NO_2 and 24-hour $PM_{2.5}$. As such, no further analyses were performed for annual NO_2, CO, PM_{10}, or annual $PM_{2.5}$ standard. A Class II Area cumulative impact analysis for 1-hour NO_2 and 24-hour $PM_{2.5}$ was conducted, as documented in **Section 8.0**.

Table 7-2. Summary of Maximum AERMOD Concentrations to Significant Impact Levels

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Secondary $PM_{2.5}$ ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	U.S. EPA SIL ($\mu g/m^3$)	Exceeds SIL? (Yes or No)	Significant Impact Area Distance (km)
NO_2	1-hour	15.01	--	15.01	7.5	Yes	15.23
	Annual	0.50	--	0.50	1.0	No	
PM_{10}	24-hour	2.12	--	2.12	5.0	No	
	Annual	0.09	--	0.09	1.0	No	
$PM_{2.5}$(1)	24-hour	1.39	0.063	1.45	1.2	Yes	1.36
	Annual	0.08	0.001	0.08	0.2	No	
CO	1-hour	432.66	--	432.66	2000.0	No	
	8-hour	230.16	--	230.16	500.0	No	

[63] https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf

8. Class II Area Cumulative Impact Analysis Results

8.1 Class II Area Air Quality Standards and PSD Increments

The discussion below applies only to those pollutants and averaging periods for which a modeled impact is predicted with AERMOD to exceed the relevant SIL. The cumulative impact analyses were conducted using methods and data described in **Sections 6** and **7** with the exception that the receptors were limited to those at which the Project has a significant modeled concentration.

The evaluation of whether the Project may cause or contribute to an exceedance of the PSD increments and NAAQS is based on the sum of the following:

- Modeled concentrations attributable to the Project;
- Modeled concentrations from "nearby" sources; and
- Representative ambient background concentration (NAAQS only).

Modeled concentrations attributable to the Project and "nearby" sources were estimated using AERMOD. An inventory of sources was developed based on information obtained from EPD to assess cumulative impacts. The modeled design short-term concentration from the Project, as well as influencing nearby emission sources, were compared with the NAAQS and PSD increments. Note that primary plus secondary $PM_{2.5}$ impacts were accounted for from the Project using the secondary $PM_{2.5}$ concentrations estimated in **Section 6.8**. For the NAAQS analysis, a conservative background concentration (see **Section 6.9**), as provided by Georgia EPD, was added to modeled design impacts.

8.2 Nearby Source Inventory

The NAAQS and PSD increment analyses include the new sources associated with the Project, along with regional inventory sources, including existing emission units at the Project site. For PSD increment analysis, only increment-consuming sources were included. For example, the 24-hour $PM_{2.5}$ increment analysis does not include increment expansion associated with the seven coal-fired steam generating units that were once operated at Plant Yates but retired or converted to gas after the minor source baseline date.

SIL modeling was used to establish the significant impact area (SIA) which denotes the maximum distance from the Project that the modeled concentrations are greater than their respective SILs. The SIAs for 1-hour NO_2 and 24-hour $PM_{2.5}$ are as shown in **The Class** II Area SIL analysis was conducted using AERMOD for the worst-case operating load on a pollutant and averaging period-specific basis (as determined in **Section 7.1**). In addition to the worst-case operating load for the proposed CT units, the SIL analysis also includes the fuel gas heaters for the short-term modeling, and fuel gas heaters, emergency generator, and fire pump for the annual modeling.

The SIL modeling analysis was used as a tool in evaluating whether the emissions of NO2, CO, PM10, and PM2.5 from the Project may cause or contribute to a NAAQS or increment exceedance. The evaluation was made using the highest short-term and highest annual modeled concentration over the five years of meteorological data modeled. For 1-hour NO2, 24-hour PM2.5, and annual PM2.5, impacts were determined based on the highest 5-year average concentrations. Additionally, the modeled NO2 concentrations were assessed using the EPA default Tier 2 ARM2 methodology for estimating NO2 concentrations from total modeled NOX emissions.

EPA guidance indicates that use of the SILs may be justified provided that the difference between ambient background concentrations representative of the Project area and the NAAQS is greater than the SIL values. For the Project, all NO2, CO, PM10, and PM2.5 monitors in the State of Georgia were evaluated and show that the difference between the monitored design values and the NAAQS is greater than the SIL values, thus justifying the use of the SILs.

Since the SIL values developed by EPA are justified for use in this case, no further modeling is needed to satisfy the required "cause or contribute" determination for those pollutants and averaging periods with modeled concentrations less than the SILs. For those pollutants and averaging periods with modeled concentrations that exceed the relevant SIL, a Class II Area cumulative impact analysis was performed to evaluate whether the Project may cause or contribute to an exceedance of the NAAQS or PSD increments. For PM2.5, the secondary PM2.5 concentrations estimated as described in **Section 6.9** were added to modeled concentrations for comparison with the SILs.

A comparison of the overall maximum modeled concentrations with the SILs is presented in **Table 7-2** for the worst-case operating load. As is depicted in **Table 7-2,** all modeled concentrations are below their respective SILs with the exception of 1-hour NO2 and 24-hour PM2.5. As such, no further analyses were performed for annual NO2, CO, PM10, or annual PM2.5 standard. A Class II Area cumulative impact analysis for 1-hour NO2 and 24-hour PM2.5 was conducted, as documented in **Section 8.0.**

Table 7-2 and were used to support development of an appropriate regional source inventory.

The regional source inventory was developed based on EPD's PSD Permit Guidance Document (Section 5.3) for each pollutant with modeled concentrations that exceed the SIL. For 24-hour $PM_{2.5}$, the modeled SIA is 1.36 km. 50 km was added to the 24-hour $PM_{2.5}$ SIA to determine which sources should be considered in the cumulative modeling for a distance of 51.36 km. For 1-hour NO_2 (which has an SIA of 15.23 km), EPD's guidance suggests use of US EPA guidance, which generally suggests a regional source inventory should not extend much beyond 20 km for 1-hour averaging periods since transport distances over 1 hour are more limited. Therefore, the regional source inventory for 1-hour NO_2 was based on a 25-km distance from the Project site.

The regional source inventory for Georgia was initially generated using EPD's "PSD Modeling Tool" provided on EPD's website, which provides an off-site inventory for the applicable pollutants based on the location of the subject source. The initial inventory was then screened using the "20D Rule" as recommended by EPD. The 20D rule allows for the screening of inventory sources based on annual allowable emissions and distance from the Project site. As required by EPD, in employing the 20D rule, all sources located within 2 km from each other were identified. The emissions of these sources were then grouped together for the 20D evaluation. Sources located within the SIA were not excluded using the 20D rule and were included in the modeling.

Individual sources or source groups within the screening area may be removed from the inventory if the source's or grouped sources' allowable emissions (in tons per year) are less than 20D, where D is the distance (in km) from the project source to the inventory source for short-term modeling.

Once sources were screened based on the 20D rule, those that are required to be included in the background inventory were added to the model based on how they are represented in the AERMOD-ready files provided by EPD's PSD Modeling Tool. For those sources that have "ND" as stack parameters, based on past experiences with EPD, the following default parameters were used:

- Stack Height – 10 meters
- Stack Temperature – 293 Kelvin
- Stack Velocity – 15 meters/second
- Stack Diameter – 0.5 meters

In addition, secondary $PM_{2.5}$ from nearby sources was accounted for in the cumulative NAAQS and PSD increment consumption analyses. Specifically, SO_2 and NO_X emissions from those nearby sources that were

identified and modeled as part of the $PM_{2.5}$ cumulative modeling assessment were obtained from EPD's "PSD Modeling Tool". **Table 8-1** provides a list of the sources that were included in the $PM_{2.5}$ cumulative modeling along with their facility total SO_2 and NO_X emissions based on data in EPD's "PSD Modeling Tool". The total precursor emissions data from these sources were combined and used to estimate secondary $PM_{2.5}$ concentrations using the MERPs values for the Tallapoosa County source and methodology described in **Section 6.8**. The secondary $PM_{2.5}$ concentrations attributable to nearby sources was added to the proposed Project secondary $PM_{2.5}$ to estimate the total secondary $PM_{2.5}$ from the project and nearby sources as shown in **Table 8-2**. This approach is highly conservative from an increment consumption perspective given the large decrease in SO_2 emissions (a primary secondary $PM_{2.5}$ precursor) since the major source baseline date as shown in **Figure 6-9**. This approach is also conservative when assessing NAAQS compliance because the ambient background monitor used for $PM_{2.5}$ already reflects nearby source contributions of secondary $PM_{2.5}$ from their SO_2 and NO_X precursor emission.

The complete regional source inventory (including screening steps) is provided within the electronic modeling archive as part of **Appendix G**.

Table 8-1. SO_2 and NO_X Emissions from Nearby Sources

Facility	Total NO_X Emissions (tpy)	Total SO_2 Emissions (tpy)
Georgia Power - Plant Yates	4,677	187
Tenaska Georgia Generating Station	8,174	279
Hawk Road Energy Facility	1,511	30
Chattahoochee Energy Facility	180	11
MEAG Wansley	260	13
Southern Power Wansley	520	26
Total:	**15,322**	**546**

Table 8-2. Nearby Source Estimated Secondary $PM_{2.5}$ Concentrations

Averaging Period	NO_X		SO_2		Nearby Source Estimated Secondary $PM_{2.5}$ Concentration ($\mu g/m^3$)
	EPA MERP (TPY)	Nearby Source Precursor Emissions (TPY)	EPA MERP (TPY)	Nearby Source Precursor Emissions (TPY)	
24-hr $PM_{2.5}$	16,767	15,322	2,593	546	1.4

8.3 NAAQS Analysis Results

A summary of the NAAQS analysis is presented below in **Table 8-3**. The modeled concentrations presented represent the Project (including the secondary $PM_{2.5}$ estimated in **Section 6.9**), existing Plant Yates sources, and nearby background sources. The modeled concentrations were added to representative ambient background concentrations to estimate the total concentrations that were then compared to the NAAQS. As shown, the total concentrations for 1-hour NO_2 and 24-hour $PM_{2.5}$ are less than the NAAQS. The results of the cumulative modeling analysis indicate that the Project will not cause or contribute to a violation of the 1-hour NO_2 and 24-hour $PM_{2.5}$ NAAQS. **Figure 8-1** and **Figure 8-2** illustrate the results of the 1-hour NO_2 and 24-hour $PM_{2.5}$ NAAQS analyses. As shown in **Figure 8-1** and **Figure 8-2**, all maximum concentrations fall within 100-meter spaced receptors.

Table 8-3. Summary of NAAQS Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration[4] (µg/m³)	Secondary $PM_{2.5}$[3] (µg/m³)	Ambient Background Concentration[1] (µg/m³)	Total Concentration[2] (µg/m³)	NAAQS (µg/m³)
NO_2	1-hour	98th	140.85 (0.00016)	--	30.30	171.15	188
$PM_{2.5}$	24-hour	98th	1.09 (0.53)	1.41	16.20	18.70	35

(1) Ambient background concentrations from the **Yorkville, GA monitor**.
(2) Total concentration includes Project, nearby sources, and monitored background concentrations.
(3) Secondary PM2.5 concentrations reflect Project contribution (0.063 µg/m³) and contribution from NO_x and SO_2 emissions associated with nearby source inventory (1.35 µg/m³).
(4) The concentration within parentheses ( ) is the contribution due to the Project and existing sources at Plant Yates.

Source: EPA 40 CFR 50

8.4 PSD Increment Analysis Results

A summary of the PSD increment analysis is presented in **Table 8-4** for 24-hour $PM_{2.5}$. PSD increment modeling analysis was not required for 1-hour NO_2 because there is no PSD increment established for 1-hour NO_2. The modeled concentrations presented in **Table 8-2** represent the Project (including the secondary $PM_{2.5}$ estimated in **Section 6.9**), and nearby background PSD increment-consuming sources. As summarized in Table 8-2, the Project will not cause or contribute to a violation of the 24-hour $PM_{2.5}$ PSD increment. **Figure 8-2** illustrates the results of the 24-hour $PM_{2.5}$ PSD increment analysis. As shown in **Figure 8-2**, all maximum concentrations fall within 100-meter spaced receptors.

Table 8-4. Summary of PSD Increment Analysis

Pollutant	Averaging Period	Rank	Modeled Concentration (µg/m³)[2]	Secondary $PM_{2.5}$[1] (µg/m³)	Total Concentration (µg/m³)	PSD Increment (µg/m³)
$PM_{2.5}$	24-hour	H2H	1.55 (0.83)	1.41	2.96	9

(1) Secondary values reflect project contribution (0.063 µg/m³) and contribution from SO_2 and NO_x emissions associated with nearby source inventory (1.35 µg/m³).
(2) The concentration within parentheses ( ) is the contribution due to the Project.

Figure 8-1. NO_2 NAAQS Analysis Concentration Isopleths (includes ambient background)

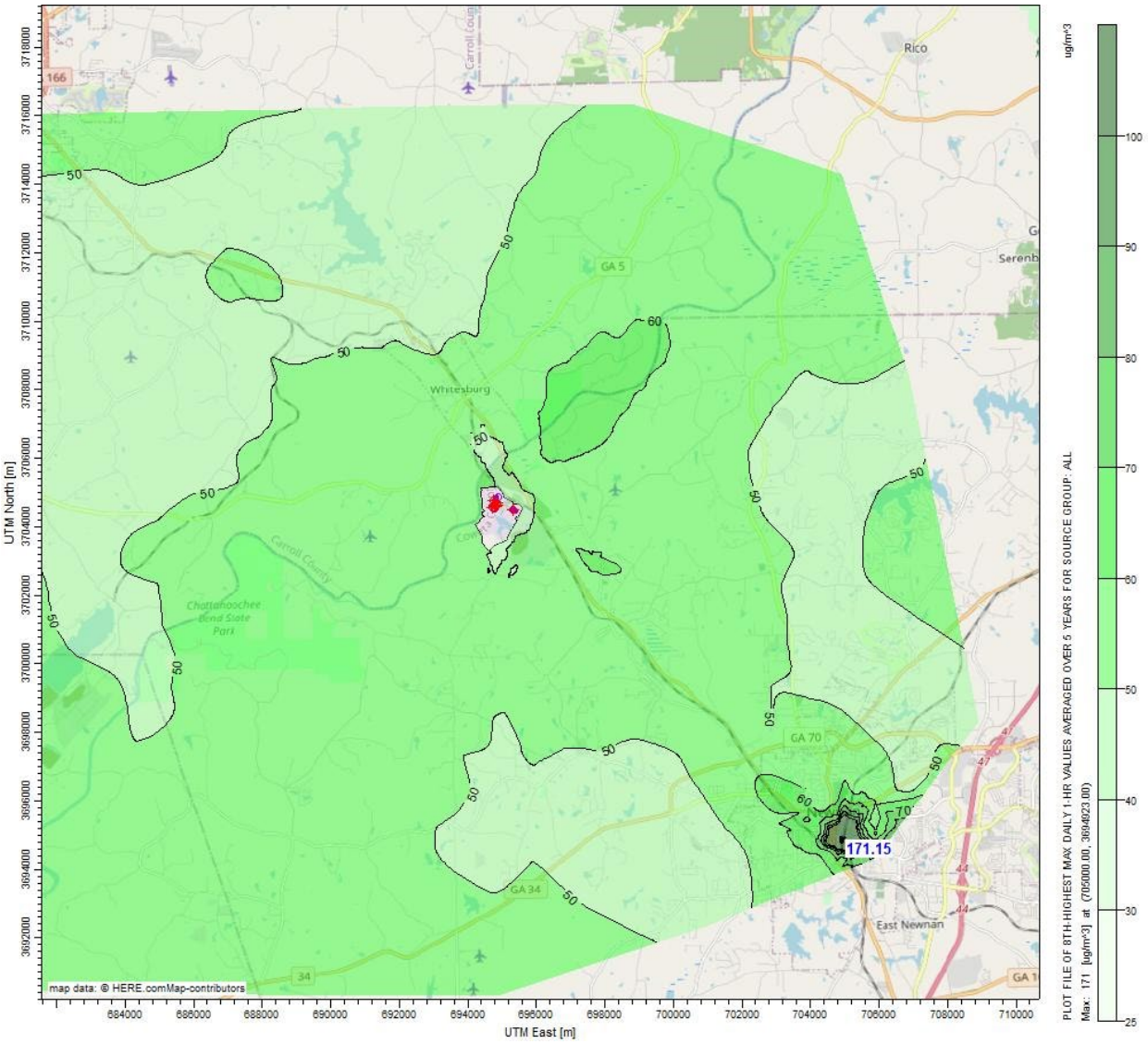


Figure 8-2. $PM_{2.5}$ NAAQS Analysis Concentration Isopleths (includes ambient background)

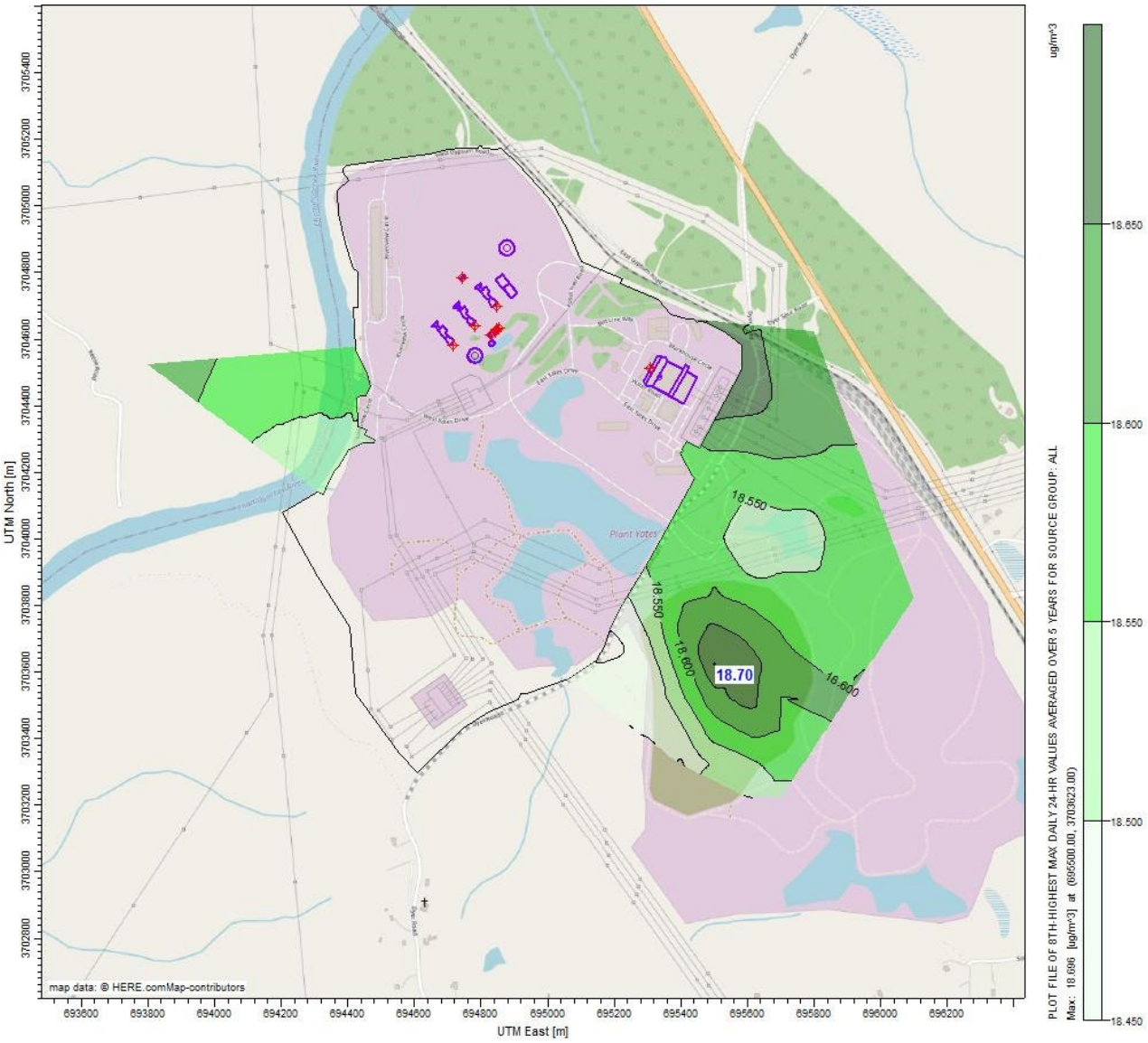
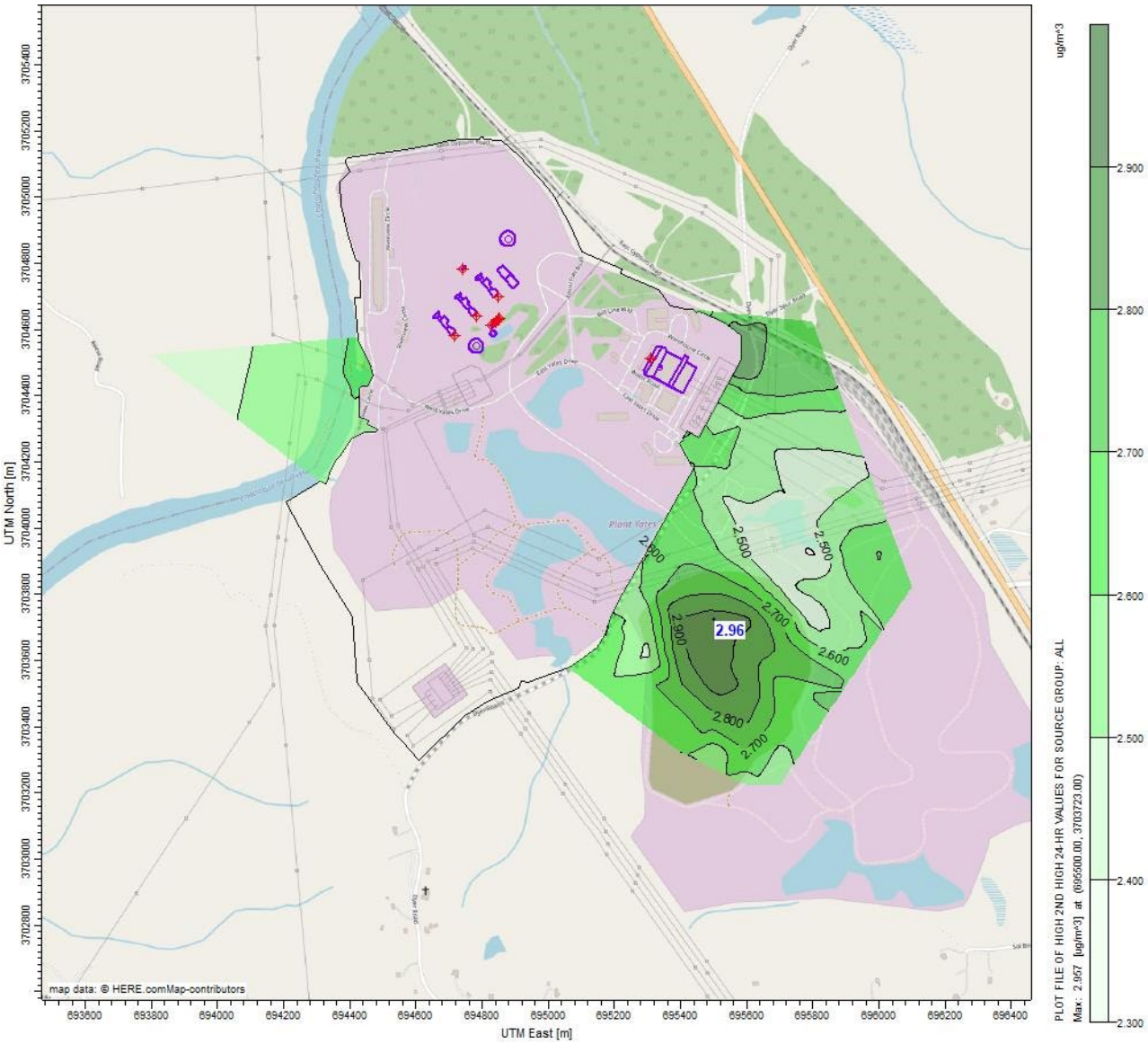


Figure 8-3. $PM_{2.5}$ PSD Increment Concentration Isopleths



9. Other PSD Requirements

9.1 Class I Area Impact Analysis

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. NO_2, PM_{10}, and $PM_{2.5}$ are the only pollutants for which the Project is subject to Class I area review. According to 40 CFR §52.21(p), sources located within 300 km of a Class I area may be required to demonstrate that the proposed project will not cause or contribute to an exceedance of the PSD Class I increments or adversely affect certain air quality-related values (AQRVs) (including visibility and acid deposition). The five PSD Class I areas located within 300 km of the Project site are pictured in **Figure 9-1** and listed in **Table 9-1**.

The Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report (Revised 2010) (FLAG 2010) guidance document contains a screening approach that is designed to screen out projects with small impacts from the need to conduct an AQRV analysis for nearby Class I areas. The FLAG 2010 guidance states that a proposed source with a Q/D ratio less than 10 will likely not have an adverse impact on air quality related values, where 'Q' is the annual steady-state equivalent emission rate based on the sum of NO_X, SO_2, filterable PM_{10}, and H_2SO_4 emissions (expressed in tons per year, based on maximum 24-hour emissions) and 'D' is the distance (km) to the closest Class I area. Since the proposed CT units will be fueled by natural gas, or distillate oil when gas is not available, the Project has a 'Q' value for each fuel. Note that all SO_2 emissions from the Project are assumed to form H_2SO_4 prior to release, so no SO_2 emissions were included in the Q/D calculation for the Project.

Table 9-1 provides the distance (D) from the proposed Project to each Class I area along with the Q/D ratio. For natural gas, 'Q' is 746.4 tons per year based on the following calculation: 41.0 lb/hr (NO_X) + 7.0 lb/hr (PM_{10}, filterable) + 8.8 lb/hr (H_2SO_4) = 56.8 lbs/hr/CT x 3 CT units = 170.4 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 746.4 tons/year. Relative to the Cohutta Wilderness Area, Q = 746.4 tons/year, d=156, and Q/D ratio = 4.8. For distillate oil, 'Q' is 1,544.0 tons per year based on the following calculation: 74.0 lb/hr (NO_X) + 35.4 lb/hr (PM_{10}, filterable) + 8.1 lb/hr (H_2SO_4) = 117.5 lbs/hr/CT x 3 CT units = 352.5 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 1,544.0 tons/year. Relative to the Cohutta Wilderness Area, Q = 1,544.0 tons/year, d=156, and Q/D ratio = 9.9.

As shown in **Table 9-1**, Project's most conservative Q/D for natural gas is 4.8 and for distillate oil is 9.9, both below the screening threshold. GPC prepared a Request for Applicability of Class I Area Modeling Analysis which was submitted to the United States Forest Service (USFS) for review to confirm that an assessment of AQRVs will not be required. On November 20, 2023, the USFS FLM provided a waiver from the need to perform an AQRV analysis based on the submittal. The FLM correspondence is included as an attachment in **Appendix H**. Since the USFS has the closest Class I area to the proposed Project, it is considered the lead agency for this Project's AQRV waiver request. As such, the National Park Service (NPS) was not contacted relative to an AQRV waiver request for the Great Smokey Mountains National Park, which is the closest Class I area managed by the NPS.

9.1.1 Class I SIL Analysis

In accordance with Appendix W (Section 4.2.c.i), because AERMOD (Version 23132) was used for the Project's nearfield assessment, it can be utilized in a screening-level analysis to estimate the Project's potential for a significant modeled impact at the PSD Class I areas listed above. As such, AERMOD was used as a screening tool with the meteorological data described in **Section 6.5** and with a radial arc of receptors located 50 km from the Project. Receptors along the 50-km arc were placed every 1 degree for 360 degrees.

The results of the Class I area SIL modeling are presented in **Table 9-2**. As shown in **Table 9-2**, the maximum modeled concentration for each relevant pollutant along the entire arc of receptors at 50-km from the Project is below its respective SIL. As such, no additional Class I modeling was conducted.

Table 9-1. Class I Areas Q/D Calculations

Class I Area	Location[1] UTMX UTMY (meters)	Distance from Project (km)[2]	Natural Gas Scenario Emissions (tpy)	Natural Gas Scenario Q/D	ULSD Scenario Emissions (tpy)	ULSD Scenario Q/D
Cohutta Wilderness	719584.34, 3858797.64	156	746.6	4.8	1544.0	9.9
Joyce Kilmer – Slickrock Wilderness Area	778216.12, 3916471.09	228	746.6	3.3	1544.0	6.8
Great Smoky Mountains National Park	784777.80, 3928959.44	242	746.6	3.1	1544.0	6.4
Sipsey Wilderness	459936.36, 3797758.26	253	746.6	3.0	1544.0	6.1
Shining Rock Wilderness	872196.31, 3919857.76	279	746.6	2.7	1544.0	5.5

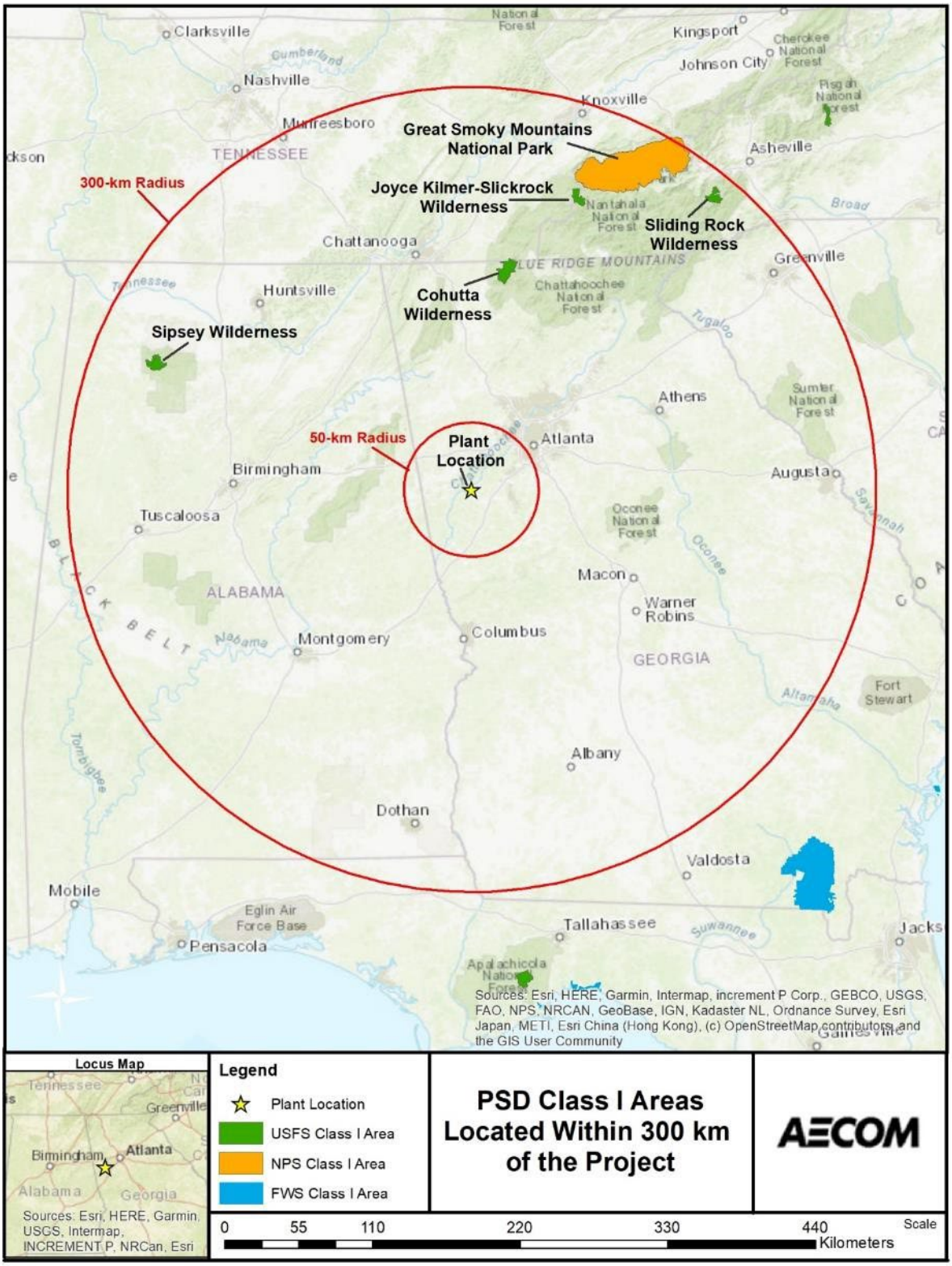
(1) Cohutta Wilderness and the Project are in UTM Zone 16. Sipsey Wilderness, Joyce Kilmer – Slickrock Wilderness Area, Great Smoky Mountains National Park, and Shining Rock Wilderness are in UTM Zone 17.
(2) Project Location UTM Zone 17 (meters): X=694,900, Y=3,704,323

Table 9-2. Class I Area – SIL Modeling Results

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)[1]	Secondary $PM_{2.5}$[1] (µg/m^3)	Total Concentration (µg/m^3)	Class I SILs (µg/m^3)	% of Class I SILs
NO_2	Annual	0.006	--	0.006	0.1	6%
PM_{10}	24-hour	0.136	--	0.137	0.3	46%
	Annual	0.005	--	0.012	0.2	6%
$PM_{2.5}$	24-hour	0.136	0.063	0.199	0.27	74%
	Annual	0.005	0.001	0.006	0.05	12%

(1) Project secondary $PM_{2.5}$ is based on data in **Section 6.8**.

Figure 9-1. PSD Class I Areas Within 300 km of the Project



9.2 Soils and Vegetation

As required, an analysis of the Project's potential impact on soils and vegetation in the vicinity of the Project was performed by comparing maximum modeled concentrations from the SIL analysis (see **Section 7**) with secondary NAAQS. Secondary NAAQS define maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS have been adopted for NO_2, PM_{10} and $PM_{2.5}$.

The highest modeled concentrations of NO_2, PM_{10}, and $PM_{2.5}$ from the Project were compared to each secondary NAAQS as shown in **Table 9-3**. The modeled concentrations are all well below each applicable secondary NAAQS; therefore, no significant impacts on local soils and vegetation are expected as a result of the Project.

Table 9-3. Comparison of Modeled Concentrations to Secondary NAAQS

Pollutants	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Secondary $PM_{2.5}$ ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
NO_2	Annual	0.50	--	0.50	100
$PM_{2.5}$	24-hour	1.39	0.063	1.45	35
	Annual	0.08	0.001	0.08	15
PM_{10}	24-hour	2.12	--	2.12	150

9.3 Growth-Related Impacts

A qualitative evaluation of the general commercial, residential, industrial, and other growth associated with the Project was conducted. The Project is not expected to employ many new additional employees at this time. Therefore, secondary growth is not expected, and an analysis of such growth was not performed.

9.4 Visibility Impairment

The PSD regulations require an evaluation of the impact of the Project emissions on visibility. The primary pollutants responsible for visibility impairment are particulates, SO_2, and NO_x; however, since SO_2 emissions from the Project are minimal, this analysis focuses primarily on PM and NO_x. A visibility analysis was conducted with US EPA's VISCREEN model for Chattahoochee Bend State Park in Georgia, approximately 5.4 km to the west of the Project site and the nearest state park to the Project site.

The analysis was conducted in accordance with US EPA's Workbook for Plume Visual Impacts Screening and Analysis (Revised) ("Workbook"; US EPA, 1992). The VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (C_p). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for C_p are considered perceptible.

The VISCREEN model Workbook offers two levels of analysis. Level 1 screening analysis is the most simplified and conservative approach, employing worst-case default meteorological data. Level 2 analysis allows refinement of meteorological conditions as well as site-specific conditions such as complex terrain. Initially, the Level 1 analysis was conducted and indicated ΔE and C_p values were above the screening thresholds. Therefore, a Level 2 analysis was conducted.

The Level 2 analysis was conducted with five years of surface observations from Hartsfield-Jackson Atlanta International Airport (KATL) and upper air data from Atlanta Regional Airport – Falcon Field (KFFC). Terrain elevation differences between the stack tops (187 m) and Chattahoochee Bend State Park maximum elevation (approximately 303 m) is less than 500 meters.

The source data required by VISCREEN are total NO_X emissions (222 lb/hr), particulate emissions (106.07 lb/hr), and primary SO_4 (24.24 lb/hr) for the Project. These emissions represent worst case emission rates.

The 22.5 degree (°) wind direction sectors that would transport emissions from the Project site toward Chattahoochee Bend State Park, along with the closest distance from the park to the Project site, are shown in **Table 9-4**. The location of Chattahoochee Bend State Park relative to the Project site is shown in **Figure 9-2**.

Table 9-4. VISCREEN Level 2 Input Data

22.5º Wind Sectors	Closest Distance to the Source (km)	Furthest Distance from the Source (km)	Level 2 Worst Case Stability Class	Level 2 Worst Case Wind Speed (m/s)
243.5 – 266.0	5.9 km	11.9	D	5
221.0 – 243.5	5.4 km	11.9	D	5

Based on this information, and the five years of meteorological data, a table of joint frequency of occurrence of wind speed, wind direction, and stability class was developed as outlined in the Workbook. The dispersion conditions, defined by wind speed and stability class, were ranked by evaluating the product of σ_y, σ_z, and u, where u is the wind speed and σ_y and σ_z are the Pasquill-Gifford horizontal and vertical diffusion coefficients for the given stability class and downwind distance. The dispersion conditions were then ranked in ascending order according to the value of $\sigma_y\sigma_z u$ as shown in **Table 9-5**.

According to the Workbook, VISCREEN is to be applied with the worst-case meteorological conditions that have a $\sigma_y\sigma_z u$ product with a cumulative probability of one percent. That is, the dispersion condition is selected such that the sum of all frequencies of occurrence of conditions worse than this condition totals one percent. Note that as recommended by the Workbook, dispersion conditions that result in greater than 12 hours of plume transport time are discounted from the analysis, since it is unlikely that steady-state plume conditions would persist for more than 12 hours.

Table 9-5. Dispersion Condition Frequency Analysis

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time (hours)	Frequency by Time of Day (%)				Cumulative Frequency by Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)		0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
Sector 1											
F	1	6244	3	0.146	0.055	0.027	0.091	0.146	0.055	0.027	0.091
F	2	12488	1	1.159	0.055	0.009	1.013	1.305	0.110	0.037	1.104
E	1	15379	3	0.000	0.000	0.000	0.000	1.305	0.110	0.037	1.104
F	3	18731	1	0.000	0.000	0.000	0.000	1.305	0.110	0.037	1.104
E	2	30758	1	0.128	0.064	0.000	0.173	1.433	0.173	0.037	1.278
D	1	33262	3	0.000	0.000	0.000	0.000	1.433	0.173	0.037	1.278
E	3	46137	1	1.835	0.137	0.027	1.962	3.268	0.310	0.064	3.240
E	4	61516	0	0.876	0.091	0.037	1.068	4.144	0.402	0.100	4.308
D	2	66523	1	0.000	0.046	0.000	0.009	4.144	0.447	0.100	4.317
E	5	76895	0	0.000	0.000	0.000	0.000	4.144	0.447	0.100	4.317
D	3	99785	1	0.000	0.137	0.018	0.055	4.144	0.584	0.119	4.372
D	4	133046	0	0.319	0.292	0.100	0.621	4.463	0.876	0.219	4.993
D	**5**	**166308**	**0**	**0.849**	**0.383**	**0.292**	**1.104**	**5.312**	**1.260**	**0.511**	**6.097**
D	6	199570	0	0.529	0.329	0.274	0.484	5.842	1.588	0.785	6.581
D	7	232831	0	0.274	0.411	0.319	0.192	6.115	1.999	1.104	6.773
D	8	266093	0	0.082	0.246	0.201	0.137	6.198	2.245	1.305	6.909

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time (hours)	Frequency by Time of Day (%)				Cumulative Frequency by Time of Day (%)			
Stability Class	Wind Speed (m/s)	(m^3/s)		0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
Sector 2											
F	1	5534	3	0.173	0.009	0.000	0.091	0.173	0.009	0.000	0.091
F	2	11068	1	1.597	0.000	0.000	1.250	1.771	0.009	0.000	1.342
E	1	13583	3	0.000	0.000	0.000	0.000	1.771	0.009	0.000	1.342
F	3	16603	1	0.000	0.000	0.000	0.000	1.771	0.009	0.000	1.342
E	2	27166	1	0.246	0.018	0.000	0.256	2.017	0.027	0.000	1.597
D	1	29120	3	0.000	0.000	0.000	0.000	2.017	0.027	0.000	1.597
E	3	40748	1	2.200	0.119	0.018	2.145	4.217	0.146	0.018	3.742
E	4	54331	0	1.396	0.128	0.009	1.533	5.613	0.274	0.027	5.276
D	2	58240	1	0.000	0.027	0.000	0.000	5.613	0.301	0.027	5.276
E	5	67914	0	0.000	0.000	0.000	0.000	5.613	0.301	0.027	5.276
D	3	87361	1	0.000	0.082	0.018	0.009	5.613	0.383	0.046	5.285
D	4	116481	0	0.402	0.319	0.064	0.730	6.015	0.703	0.110	6.015
D	**5**	**145601**	**0**	**0.712**	**0.539**	**0.392**	**1.150**	**6.727**	**1.241**	**0.502**	**7.165**
D	6	174721	0	0.502	0.465	0.511	0.539	7.229	1.707	1.013	7.704
D	7	203842	0	0.201	0.256	0.484	0.219	7.430	1.962	1.497	7.923
D	8	232962	0	0.082	0.192	0.383	0.119	7.512	2.154	1.880	8.041

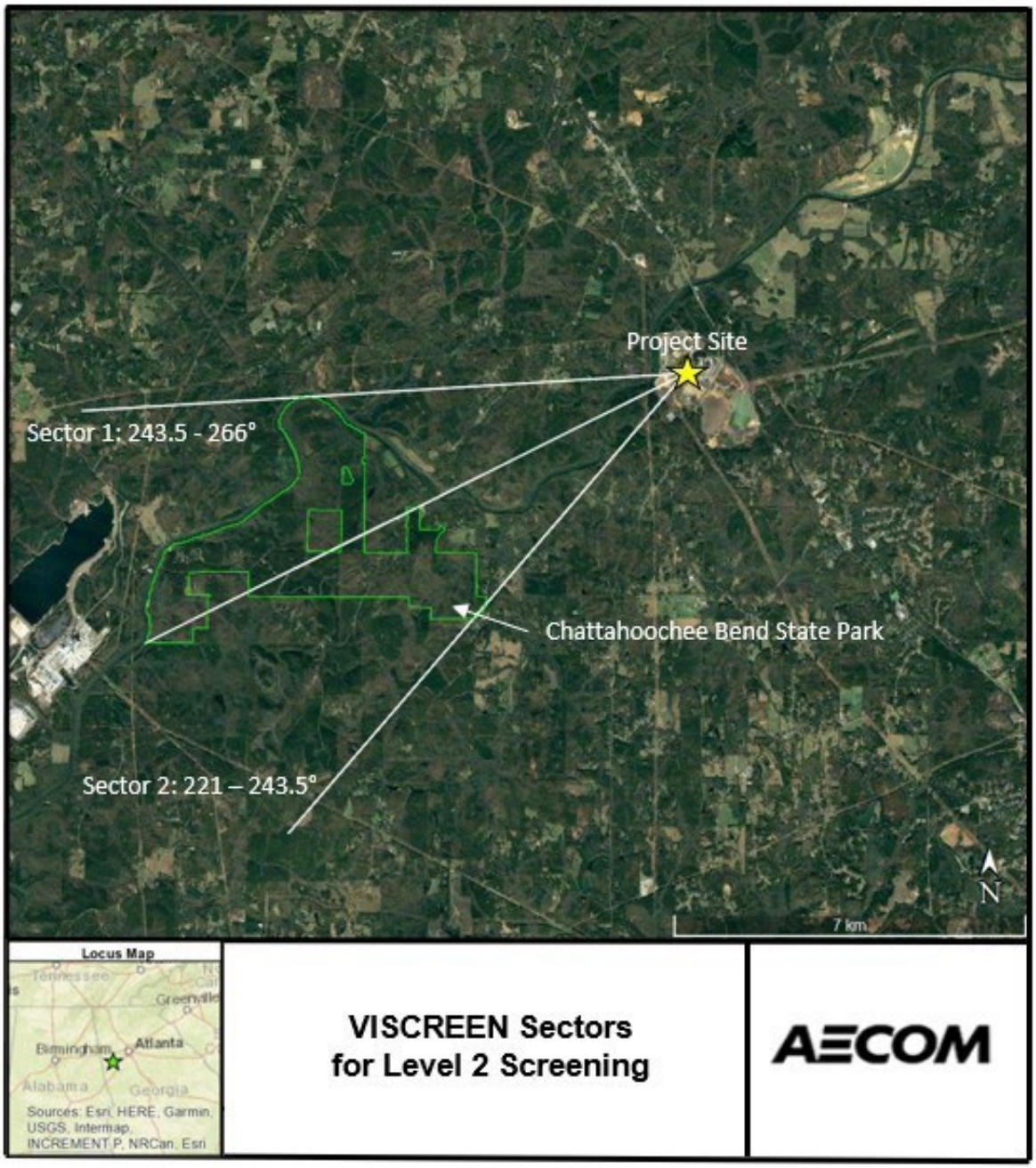
According to **Table 9-5**, the worst-case daylight (6 am – 6 pm) dispersion conditions with cumulative frequency of 1 percent are D stability, 5 m/sec. Therefore, VISCREEN was applied with D stability and a wind speed of 5 m/sec. As recommended by the Workbook, a visual range of 25 kilometers was used (see Figure 9 of the Workbook). The VISCREEN results are summarized in **Table 9-6** using maximum emissions during normal operations. VISCREEN provides results of ΔE and C_p for both sky and terrain backgrounds. The results are below the significance criteria for both sky and terrain background for both ΔE and $C\rho$) for all view angles except for the terrain background at theta = 10. However, given that there are no elevated scenic vistas with terrain as background for this area, visual impacts on terrain should not be a critical value in determining plume perceptibility for the Project.

Table 9-6. VISCREEN Results Inside Class I Area

Background	Theta[1]	Azimuth	Distance	Alpha	ΔE		Contrast ($C\rho$)	
					Criteria	Plume	Criteria	Plume
SKY	10	160	12.2	9	2.00	1.262	0.05	0.011
SKY	140	160	12.2	9	2.00	0.466	0.05	-0.014[2]
TERRAIN	10	160	12.2	9	2.00	3.262	0.05	0.039
TERRAIN	140	160	12.2	9	2.00	0.772	0.05	0.031

1. VISCREEN results are provided for the two VISCREEN default worst-case theta angles. The two theta angles represent the sun being in front of the observer (theta = 10 degrees) and behind the observer (theta = 140 degrees).
2. A negative C_p means the plume has a darker contrast than the background sky.

Figure 9-2. VISCREEN Level II Analysis Wind Sectors



STF-PIA-10-9 Attachment

10. Toxics Impact Assessment

10.1 Introduction

An assessment of potential impacts of toxic air pollutants (TAP) following EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*[64] ("*Guideline*" hereinafter) was conducted for the Project. The basic steps in the air toxics impact assessment are as follows:

1. Quantify emissions of TAPs from each emission unit;
2. Determine the acceptable ambient concentrations (AAC) for each TAP;
3. Conduct a dispersion modeling analysis to compute an ambient air concentration; and
4. Compare the modeled concentration to the AAC.

The following sections present the data and methodology used in the TAP analysis as well as comparison of modeled TAP concentrations to the AACs.

10.2 Toxic Air Pollutant Emissions

GPC quantified emissions of TAPs from the entire site (Project source and existing sources). To assess the potential impacts of TAPs, total site-wide emission rates for each TAP were evaluated first using a screening procedure. Per the *Guideline*, if a TAP's total emission rate is below the associated Minimum Emission Rate (MER), no further analysis is required. The MER for each TAP is provided within Appendix A of the *Guideline*. For those TAPs with total emission rates above the MER, further analysis (modeling to compare against the AAC) is required. The following pollutants had emission rates above the associated MER and required modeling:

- Arsenic
- Beryllium
- Cadmium
- Chromium (Total)
- Lead
- Manganese
- Nickel
- Selenium
- Acetaldehyde
- Acrolein
- Ammonia
- Benzene
- 1,3-Butadiene
- Formaldehyde
- Propylene Oxide
- Sulfuric Acid
- Naphthalene

It is understood that if non-point source emissions account for more than 20 percent of the MER for a TAP, additional review of that TAP is also required (per *Guideline*, "If facility-wide emissions are mainly emitted as volume or area sources, MER should not be used for screening out of the modeling analysis."). No additional pollutants were pulled into the analysis based on this step of the review.

[64]Georgia EPD, "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*" Revised May 2017.

A comparison of the total site-wide emissions (Project emissions in addition to existing source emissions) and MERs is provided in **Table 10-1.**

Table 10-1. Comparison of Facility-Wide TAP Emissions to MERs

Pollutants	Annual Emissions Gas-fired (tpy)	Annual Emissions – Oil-fired (tpy	MER (lb/yr)	MER (tpy)	Exceeds MER – Gas-fired?	Exceeds MER – Oil-fired?	AAC Analysis Required?
Arsenic	1.04E-02	2.13E-01	5.67E-02	2.83E-05	Y	Y	Y
Beryllium	6.26E-04	6.20E-03	9.73E-01	4.87E-04	Y	Y	Y
Cadmium	5.73E-02	1.24E-01	1.35E+00	6.76E-04	Y	Y	Y
Chromium (total)	7.29E-02	2.50E-01	5.84E+01	2.92E-02	Y	Y	Y
Cobalt	4.37E-03	2.58E-03	1.17E+01	5.84E-03	N	N	N
Lead	2.61E-02	2.78E-01	5.84E+00	2.92E-03	Y	Y	Y
Manganese	2.23E-02	1.49E+01	1.22E+01	6.08E-03	Y	Y	Y
Mercury	1.35E-02	3.05E-02	7.30E+01	3.65E-02	N	N	N
Nickel	1.09E-01	1.51E-01	3.86E+01	1.93E-02	Y	Y	Y
Selenium	2.06E-03	4.70E+00	2.34E+01	1.17E-02	N	Y	Y
Acetaldehyde	8.69E-01	4.66E-04	1.11E+03	5.54E-01	Y	N	Y
Acrolein	1.39E-01	6.94E-05	4.87E+00	2.43E-03	Y	N	Y
Ammonia	1.64E+02	1.49E+02	2.43E+04	1.22E+01	Y	Y	Y
Benzene	3.28E-01	1.10E+00	3.16E+01	1.58E-02	Y	Y	Y
1,3-Butadiene	9.36E-03	2.02E-05	7.30E+00	3.65E-03	Y	N	Y
Dichlorobenzene	3.69E-02	3.69E-02	N/A	N/A	N	N	N
Ethylbenzene	6.95E-01	8.45E-03	2.43E+05	1.22E+02	N	N	N
Formaldehyde	7.52E+00	7.19E+00	2.67E+02	1.34E-01	Y	Y	Y
Hexane	5.53E+01	5.53E+01	1.70E+05	8.52E+01	N	N	N
Propylene Oxide	6.30E-01	0.00E+00	6.57E+02	3.28E-01	Y	N	Y
Sulfuric Acid	4.66E+01	4.40E+01	1.17E+02	5.84E-02	Y	Y	Y
Toluene	2.93E+00	9.29E-01	1.22E+06	6.08E+02	N	N	N
Xylene	1.39E+00	1.52E-02	2.43E+04	1.22E+01	N	N	N
Acenaphthene	6.89E-05	6.89E-05	N/A	N/A	N	N	N
Acenaphthylene	8.32E-05	8.32E-05	N/A	N/A	N	N	N
Anthracene	7.81E-05	7.81E-05	N/A	N/A	N	N	N
Benz(a)anthracene	5.79E-05	5.79E-05	N/A	N/A	N	N	N
Benzo(a)pyrene	3.77E-05	3.77E-05	N/A	N/A	N	N	N
Benzo(b)flouoranthene	5.84E-05	5.84E-05	N/A	N/A	N	N	N
Benzo(g,h,I)perylene	3.87E-05	3.87E-05	N/A	N/A	N	N	N
Benzo(k)fluoranthene	5.60E-05	5.60E-05	N/A	N/A	N	N	N
Chrysene	5.97E-05	5.97E-05	N/A	N/A	N	N	N

Pollutants	Annual Emissions Gas-fired (tpy)	Annual Emissions – Oil-fired (tpy	MER (lb/yr)	MER (tpy)	Exceeds MER – Gas-fired?	Exceeds MER – Oil-fired?	AAC Analysis Required?
Dibenzo(a,h)anthracene	3.81E-05	3.81E-05	N/A	N/A	N	N	N
Dimethylbenz(a)Anthracene, 7,12-	4.92E-04	4.92E-04	N/A	N/A	N	N	N
Fluoranthene	1.07E-04	1.07E-04	N/A	N/A	N	N	N
Fluorene	1.36E-04	1.36E-04	N/A	N/A	N	N	N
Indeno(1,2,3-cd)pyrene	5.66E-05	5.66E-05	N/A	N/A	N	N	N
Methylchloanthrene, 3-	5.53E-05	5.53E-05	N/A	N/A	N	N	N
Methylnaphthalene, 2-	7.38E-04	7.38E-04	N/A	N/A	N	N	N
Naphthalene	4.74E-02	6.77E-01	7.30E+02	3.65E-01	N	Y	Y
Phenanathrene	6.49E-04	6.49E-04	N/A	N/A	N	N	N
Pyrene	1.66E-04	1.66E-04	N/A	N/A	N	N	N
Total POM	5.13E-02	7.55E-01	N/A	N/A	N	N	N

Source: MER - Georgia EPD

10.3 Acceptable Ambient Concentrations

The *Guideline* provides the methodology for determining the AAC for TAPs based on various sources of toxicity data. EPD maintains a database of AACs for common TAPs[65]. AACs for all TAPs considered in the analysis were obtained from the EPD database.

10.4 Modeling Process

The AERMOD dispersion model was used to determine the maximum short-term and annual modeled concentrations of arsenic, beryllium, cadmium, chromium (total), lead, manganese, nickel, selenium, acetaldehyde, acrolein, benzene, 1,3-butadiene, formaldehyde, propylene oxide, sulfuric acid, and naphthalene, as applicable, for comparison to the AACs.

AERMOD was applied with the same source data, receptor grid, meteorological data, building downwash file, and model options as used in the Class II air quality analysis described in **Section 6**. In addition to the Project sources, existing sources at the facility were included in the AERMOD dispersion model. These sources include existing Unit 6 and Unit 7 and the existing water bath heater.

To simplify the modeling, a conservative screening level approach was used. All sources were individually modeled with a unit emission rate (1 g/sec). The maximum impact for each source over the five years of meteorological data was scaled by its respective air toxics emission rates (in g/sec). Then all scaled concentrations for each source were summed irrespective of time and space. Finally, the site-wide totals were evaluated relative to the appropriate toxic thresholds. This is a conservative approach since the highest impacts for each source likely do not occur at the same receptor or during the same time period.

10.5 Dispersion Modeling Analysis Results

Table 10-2 summarizes the results of the dispersion modeling for short-term averages and annual averages and compares the maximum modeled concentration per pollutant and averaging period to the applicable AAC.

[65] https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling

The higher concentration using gas or oil was used for the comparison. As specified in the *Guideline*, 15-minute average concentrations were determined using a 1.32 scaling factor for 1-hour average model results. In addition, per the *Guideline*, a 24-hour AAC only needs to be evaluated if there is no annual (RBAC or RfC) threshold.

Table 10-2. Summary of Maximum AERMOD Dispersion Modeling Results vs. AACs

Pollutant	Averaging Period	Rank	Maximum Facility Total AERMOD Concentration – Gas or Oil (µg/m^3)	Maximum AERMOD Concentration - 15- min Adjustment (µg/m^3)	AAC (µg/m^3)	Percent of AAC
Arsenic	1-hr	H1H	1.46E-02	1.92E-02	2.00E-01	9.6%
	Annual	H1H	2.44E-05	--	2.33E-04	10.5%
Beryllium	1-hr	H1H	4.20E-04	5.55E-04	5.00E-01	0.1%
	Annual	H1H	8.25E-07	--	4.00E-03	0.0%
Cadmium	1-hr	H1H	7.98E-03	1.05E-02	3.00E+01	0.0%
	Annual	H1H	3.27E-05	--	5.56E-03	0.6%
Chromium (total)	24-hr	H1H	2.59E-03	--	1.20E+00	0.2%
Lead	24-hr	H1H	2.96E-03	--	1.20E-01	2.5%
Manganese	1-hr	H1H	1.02E+00	1.35E+00	5.00E+02	0.3%
	Annual	H1H	1.44E-03	--	5.00E-02	2.9%
Nickel	24-hr	H1H	1.48E-03	--	7.94E-01	0.2%
Selenium	24-hr	H1H	5.06E-02	--	4.80E-01	10.5%
Acetaldehyde	1-hr	H1H	1.41E-01	1.86E-01	4.50E+03	0.0%
	Annual	H1H	1.59E-04	--	4.55E+00	0.0%
Acrolein	1-hr	H1H	2.17E-02	2.86E-02	2.30E+01	0.1%
	Annual	H1H	2.25E-05	--	2.00E-02	0.1%
Ammonia	1-hr	H1H	2.20E+00	2.90E+00	2.40E+03	0.1%
	Annual	H1H	1.12E-02	--	1.00E+02	0.0%
Benzene	1-hr	H1H	8.30E-01	1.10E+00	1.60E+03	0.1%
	Annual	H1H	4.56E-04	--	1.30E-01	0.4%
1,3-Butadiene	1-hr	H1H	5.58E-03	7.37E-03	1.10E+03	0.0%
	Annual	H1H	5.63E-06	--	3.00E-02	0.0%
Formaldehyde	1-hr	H1H	4.27E-01	5.63E-01	2.45E+02	0.2%
	Annual	H1H	2.18E-03	--	1.10E+00	0.2%
Propylene Oxide	Annual	H1H	3.81E-05	--	2.70E+00	0.0%
Sulfuric Acid	1-hr	H1H	6.49E-01	8.56E-01	3.00E+02	0.3%
	24-hr	H1H	1.20E-01	--	2.40E+00	5.0%
Naphthalene	1-hr	H1H	1.37E-01	1.80E-01	7.50E+03	0.0%
	Annual	H1H	1.09E-04	--	3.00E+00	0.0%

STF-PIA-10-9 Attachment

As shown in **Table 10-2**, the dispersion modeling demonstrates that the site-wide emissions of each evaluated TAP do not result in an exceedance of an AAC.

11. References

Georgia Environmental Protection Division (EPD), 2017. PSD Permit Application Guidance Document. Revised February 2017. Air Quality Modeling | Environmental Protection Division (georgia.gov)

EPD 2017b. Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions. Revised May 2017. Air Quality Modeling | Environmental Protection Division (georgia.gov)

EPD 2019. Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia. Data and Modeling Unit, Planning and Support Program, Air Protection Branch, Environmental Protection Division. February 2019. Air Quality Modeling | Environmental Protection Division (georgia.gov)

National Park Service, 2010. Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Revised 2010. National Park Service, Air Resources Division; U.S. Forest Service, Air Quality Program; U.S. Fish and Wildlife Service, Air Quality Branch. http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf.

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US EPA 1980b. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA-450/2-81-078. US EPA, Research Triangle Park, NC 27711.

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US EPA 1992. Workbook for Plume Visual Impact Screening and Analysis (Revised). EPA-454/R-92-023. October 1992. https://gaftp.epa.gov/Air/aqmg/SCRAM/models/screening/viscreen/WB4PlumeVisualOCR.pdf

US EPA 2017. Guideline on Air Quality Models (Revised). Codified in the Appendix W to 40 CFR Part 51. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2017.

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US EPA 2018b. User's Guide for the AERMOD Terrain Preprocessor (AERMAP). EPA-454/B-18-004 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2022. AERMOD Implementation Guide. EPA-454-B-22-008 (June 2022) US EPA, Research Triangle Park, NC.

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Appendix A

Application Forms

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: _____ Application No. _____

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Yates Steam-Electric Generating Plant
AIRS No. (if known): 04-13- 077 - 00001
Facility Location: Street: 708 Dyer Rd.
City: Newnan Georgia Zip: 30263 County: Coweta
Is this facility a "small business" as defined in the instructions? Yes: ☐ No: ☒

2. Facility Coordinates

Latitude: 33° 27' 40" **NORTH** Longitude: 84° 53' 55" **WEST**
UTM Coordinates: 695000 m **EAST** 3704400 m **NORTH** **ZONE** 16

3. Facility Owner

Name of Owner: Georgia Power Company
Owner Address Street: 241 Ralph McGill Blvd NE, Bin 10221
City: Atlanta State: GA Zip: 30308

4. Permitting Contact and Mailing Address

Contact Person: Jon Bandzul Title: Air Manager
Telephone No.: (404) 851-7056 Ext. _____ Fax No.: _____
Email Address: JBANDZUL@southernco.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐
If Other: Street Address: _____
City: _____ State: _____ Zip: _____

5. Authorized Official

Name: Jennifer S. McNelly Title: Vice President, Environmental Affairs
Address of Official Street: 241 Ralph McGill NE, Bin 10221
City: Atlanta State: GA Zip: 30308

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: _____ Date: 12/7/23

6. Reason for Application: (Check all that apply)

☐ New Facility (to be constructed)

☒ Existing Facility (initial or modification application)

☒ Permit to Construct

☒ Permit to Operate

☐ Change of Location

☐ Permit to Modify Existing Equipment: Affected Permit No.: 4911-077-0001-V-05-0

☐ Revision of Data Submitted in an Earlier Application

Application No.: _____

Date of Original Submittal: _____

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: AECOM

Name of Contact: Jeffrey Connors

Telephone No.: (978) 905-2166 Fax No.: _____

Email Address: jeffrey.connors@aecom.com

Mailing Address: Street: 250 Apollo Dr.

City: Chelmsford State: MA Zip: 01824

Describe the Consultant's Involvement:

Prepared application

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
	6.00 Fugitive Emission Sources
1	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: April 2024

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☒ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)		
Nitrogen oxides (NOx)		
Particulate Matter (PM) (filterable only)		
PM <10 microns (PM10)		
PM <2.5 microns (PM2.5)		
Sulfur dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Greenhouse Gases (GHGs) (in CO2e)		
Total Hazardous Air Pollutants (HAPs)		
Individual HAPs Listed Below:		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy) [b]	Potential (tpy)	Actual (tpy) [c]
Carbon monoxide (CO)	>100	598.7	>100	3,623
Nitrogen oxides (NOx)	>100	4,262	>100	4,773
Particulate Matter (PM) [a]	>100	213.4	>100	530.9
PM <10 microns (PM10)	>100	213.4	>100	530.9
PM <2.5 microns (PM2.5)	>100	213.4	>100	530.9
Sulfur dioxide (SO_2)	<100	17.1	<100	47.7
Volatile Organic Compounds (VOC)	>100	121.5	>100	1,168
Greenhouse Gases (GHGs) (in CO2e)	>100,000	3,348,974	>100,000	6,424,952
Total Hazardous Air Pollutants (HAPs) [d]	>25	33.4	>25	62.7
Individual HAPs Listed Below: [d]				
Formaldehyde	<10	1.3	<10	6.5
Hexane	>10	30.1	>10	30.3
Manganese	<10	<0.1	>10	14.9

[a] The particulate matter emissions shown represent the total of filterable and condensable emissions.
[b] Current Facility Actual (tpy) emissions are based on information provided in Application No. 22345, dated December 30, 2013, for the conversion Units 6 and 7 from coal to natural gas.
[c] After Modification Actual (tpy) emissions are based on the Current Facility Actual (tpy) emissions listed plus emissions for the proposed CT units, emergency generator, emergency fire water pump engine, diesel tank, and fuel gas heaters that reflect the BACT emission limitations proposed in the accompanying application.
[d] Existing Facility Emissions Summary for Total Hazardous Air Pollutants (HAPs) and Individual HAPs listed are based on AP-42 emission factors, except for emissions of Formaldehyde from the proposed CT units which are based on the CT MACT emission limitation of 91 ppbvd, corrected to 15% O_2. Additional information available to GPC demonstrates that actual and potential emissions of HAP for the Current Facility and Existing Facility After Modification are less than 10/25 (i.e., Plant Yates is and will remain an area source for HAP emissions). GPC intends to submit this information in a separate permit application after issuance of the PSD permit for Units 8, 9, and 10.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

14. 4-Digit Facility Identification Code:

SIC Code: 4911 SIC Description: Electric Services

NAICS Code: 221112 NAICS Description: Electric Power Generation

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

GPC is proposing to construct and operate three (3) advanced class, dual-fuel simple-cycle combustion turbines (CTs) at Plant Yates to provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized. The proposed CT units will be equipped with dry low-NOx (DLN) combustors, water injection, selective catalytic reduction (SCR) systems and oxidation catalysts for air pollution control.

Equipment associated with the proposed CT units includes one (1) 3250 kW emergency generator certified to Tier 2 standards, one (1) 350 bhp fire water pump engine certified to Tier 3 standards, one (1) 5.72 million gallon distillate fuel oil storage tank equipped with submerged filling, and three (3) less than 10 MMBtu/hr natural gas-fired fuel gas heaters equipped with ultra-low NOx burners.

16. Additional information provided in attachments as listed below:

Appendix A - Application Forms

Appendix B - Plot Plan

Appendix C - Emission Calculations

Appendix D - Compliance Assurance Monitoring Forms

Appendix E - RBLC Search Results

Appendix F - Air Dispersion Modeling Files

Appendix G - FLM AQRV Waiver

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal:

☒ Flow Diagram or date of previous submittal:

18. Other Environmental Permitting Needs:

Will this facility/modification trigger the need for environmental permits/approvals (other than air) such as Hazardous Waste Generation, Solid Waste Handling, Water withdrawal, water discharge, SWPPP, mining, landfill, etc.?

☐ **No** ☒ **Yes, please list below:**

NPDES Construction Stormwater

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

19. List requested permit limits including synthetic minor (SM) limits.

Please refer to the accompanying application for requested BACT emissions limitations and operating limits.

20. Effective March 1, 2019, permit application fees will be assessed. The fee amount varies based on type of permit application. Application acknowledgement emails will be sent to the current registered fee contact in the GECO system. If fee contacts have changed, please list that below:

Fee Contact name: Bill Hodan

Fee Contact email address: bhodan@southernco.com

Fee Contact phone number: (919) 452-2726

Fee invoices will be created through the GECO system shortly after the application is received. It is the applicant's responsibility to access the facility GECO account, generate the fee invoice, and submit payment within 10 days after notification.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number [a]	Description
CT8	Combustion Turbine Unit 8	TBD	Advanced class, dual-fuel simple-cycle combustion turbines equipped with DLN, water injection, SCR, and oxidation catalyst
CT9	Combustion Turbine Unit 9	TBD	
CT10	Combustion Turbine Unit 10	TBD	
EDG	Emergency Generator	TBD	3250 kW emergency generator certified to Tier 2 standards
FWP	Fire Water Pump Engine	TBD	350 bhp fire water pump engine certified to Tier 3 standards
TNK	Distillate Oil Storage Tank	TBD	5.72 million gallon fixed roof tank equipped with submerged fill
WBH2	Fuel Gas Heater	TBD	Natural gas-fired heaters each with a heat input rating less than 10 MMBtu/hr
WBH3	Fuel Gas Heater	TBD	
WBH4	Fuel Gas Heater	TBD	

[a] Commercial negotiations with potential engineering, construction, and procurement (EPC) contractors and equipment vendors are ongoing; manufacturer and model numbers for all equipment will be provided once selected

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft [a]	Design Capacity of Unit [b] (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation [c]	
CT8 (Unit 8)	Dry Low-NOx	N/A	4,083 (Natural gas) 3,447 (Distillate oil)	~125	April 2024	TBD	N/A
CT9 (Unit 9)	Dry Low-NOx	N/A	4,083 (Natural gas) 3,447 (Distillate oil)	~125	April 2024	TBD	N/A
CT10 (Unit 10)	Dry Low-NOx	N/A	4,083 (Natural gas) 3,447 (Distillate oil)	~125	April 2024	TBD	N/A
EDG	Compression Ignition	N/A	27.34 (ULSD)	~100	April 2024	TBD	N/A
FWP	Compression Ignition	N/A	2.07 (ULSD)	~100	April 2024	TBD	N/A
WBH2	Ultra Low-NOx	N/A	<10 (Natural gas)	~15	April 2024	TBD	N/A
WBH3	Ultra Low-NOx	N/A	<10 (Natural gas)	~15	April 2024	TBD	N/A
WBH4	Ultra Low-NOx	N/A	<10 (Natural gas)	~15	April 2024	TBD	N/A

[a] This column does not have to be completed for natural gas only fired equipment.
[b] Design Capacity of Unit for CT8-10 (Units 8-10) is based on 20°F for both natural gas and distillate oil firing.
[c] CT8-10 (Units 8-10) are necessary to meet capacity needs projected to occur in Winter 2026/2027 and development activities aim to bring two of the proposed CT units online by the end of 2026 and the third online in the second quarter of 2027.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount [a]	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
CT8 (Unit 8)	Natural gas	14,213	mmscf			4.01			1,019 Btu/scf	0.5 gr/100 scf		N/A	
CT8 (Unit 8)	Distillate oil	90,780	mgal			24.98			138,000 Btu/gal	15 ppm		N/A	
CT9 (Unit 9)	Natural gas	14,213	mmscf			4.01			1,019 Btu/scf	0.5 gr/100 scf		N/A	
CT9 (Unit 9)	Distillate oil	90,780	mgal			24.98			138,000 Btu/gal	15 ppm		N/A	
CT10 (Unit 10)	Natural gas	14,213	mmscf			4.01			1,019 Btu/scf	0.5 gr/100 scf		N/A	
CT10 (Unit 10)	Distillate oil	90,780	mgal			24.98			138,000 Btu/gal	15 ppm		N/A	
EDG	ULSD	39,626	gal			198.1			138,000 Btu/gal	15 ppm		N/A	
FWP	ULSD	7,500	gal			15			138,000 Btu/gal	15 ppm		N/A	
WBH2	Natural gas	94	mmscf			0.011			1,019 Btu/scf	0.5 gr/100 scf		N/A	
WBH3	Natural gas	94	mmscf			0.011			1,019 Btu/scf	0.5 gr/100 scf		N/A	
WBH4	Natural gas	94	mmscf			0.011			1,019 Btu/scf	0.5 gr/100 scf		N/A	

[a] Potential Annual Consumption of Natural gas and Distillate oil for CT8-10 (Units 8-10) is based on ISO conditions without use of evaporative cooling and capacity factor based on design efficiency for purposes of compliance with NSPS Subpart TTTT.

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Natural gas	Williams-Transco (same as current)					
Distillate oil	TBD	TBD	TBD	TBD	TBD	TBD

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ ºF)	Storage Temp. (ºF)	Filling Method	Construction/ Modification Date [a]	Roof Type	Seal Type
TNK	Distillate Oil Storage Tank	5,720,000	Distillate Oil	0.01 psia	Ambient	Submerged Fill	TBD	Fixed, Cone	N/A

[a] CT8-10 (Units 8-10) are necessary to meet capacity needs projected to occur in Winter 2026/2027 and development activities aim to bring two of the proposed CT units online by the end of 2026 and the third online in the second quarter of 2027.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed [a]	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate [a] (acfm)
						Inlet [a]	Outlet [b]	
SCR8	CT8 (Unit 8)	Selective Catalytic Reduction	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000
SCR9	CT9 (Unit 9)	Selective Catalytic Reduction	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000
SCR10	CT10 (Unit 10)	Selective Catalytic Reduction	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000
OC08	CT8 (Unit 8)	Oxidation Catalyst	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000
OC09	CT9 (Unit 9)	Oxidation Catalyst	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000
OC10	CT10 (Unit 10)	Oxidation Catalyst	TBD	Vendor Not Yet Selected	N/A	725-825	725-825	3,700,000-5,800,000

3.0

[a] CT8-10 (Units 8-10) are necessary to meet capacity needs projected to occur in Winter 2026/2027 and development activities aim to bring two of the proposed CT units online by the end of 2026 and the third online in the second quarter of 2027.

[b] Inlet and Outlet Gas Temp. and Inlet Gas Flor Rate for the air pollution control devices depend on ambient conditions, load, and the fuel source being utilized.

Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency [a]		Inlet Stream To APCD [a]		Exit Stream From APCD [a]		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
SCR8	NOx	Up to 94%		Varies		Varies		TBD
SCR9	NOx	Up to 94%		Varies		Varies		TBD
SCR10	NOx	Up to 94%		Varies		Varies		TBD
OC08	CO	Up to 92%		Varies		Varies		TBD
OC09	CO	Up to 92%		Varies		Varies		TBD
OC10	CO	Up to 92%		Varies		Varies		TBD
OC08	VOC	Up to 80%		Varies		Varies		TBD
OC09	VOC	Up to 80%		Varies		Varies		TBD
OC10	VOC	Up to 80%		Varies		Varies		TBD

[a] Percent Control Efficiency, Inlet Stream To APCD, and Exit Stream From the APCD for the air pollution control devices vary depending on ambient conditions, load, and the fuel source being utilized.

Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions [a] (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission [b] (tpy)	Method of Determination
Natural gas CT8 (Unit 8) CT9 (Unit 9) CT10 (Unit 10)	SCR8-10 OC08-10	ST8 (Unit 8) ST9 (Unit 9) ST10 (Unit10)	NOx		41.0		878.9	2.5 ppm @ 15% O_2
			CO		35.0		2838.4	3.5 ppm @ 15% O_2
			VOC		11.4		905.6	2.0 ppm @ 15% O_2
			Total PM		7.0		130.9	Design estimate
			Total PM10		24.5		394.0	Design estimate
			Total PM2.5		24.5		394.0	Design estimate
			SO2		5.7		91.3	0.5 gr S per 100 scf
			H2SO4		8.8		139.8	0.5 gr S per 100 scf
			Pb		0.002		0.03	Emission Factors
			Total HAP		2.3		36.7	Emission Factors
			CO2e		485,807		2,584,921	Emission Factors
Distillate oil CT8 (Unit 8) CT9 (Unit 9) CT10 (Unit 10)	SCR8-10 OC08-10	ST8 (Unit 8) ST9 (Unit 9) ST10 (Unit10)	NOx		74.0		504.8	5.0 ppm @ 15% O_2
			CO		45.0		3,014	5.0 ppm @ 15% O_2
			VOC		10.3		1,041	2.0 ppm @ 15% O_2
			Total PM		35.4		251.0	Design estimate
			Total PM10		48.5		316.4	Design estimate
			Total PM2.5		48.5		316.4	Design estimate
			SO2		5.3		28.8	15 ppm S
			H2SO4		8.1		44.0	15 ppm S
			Pb		0.016		0.3	Emission Factors
			Total HAP		5.2		28.6	Emission Factors
			CO2e		561,328		3,060,087	Emission Factors

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions [a] (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission [b] (tpy)	Method of Determination
EDG	Tier 2	EDG	NOx		45.3		4.5	Emission Factors
			CO		5.4		0.5	Emission Factors
			VOC		2.3		0.2	Emission Factors
			Total PM		1.2		0.1	Emission Factors
			Total PM10		1.1		0.1	Emission Factors
			Total PM2.5		1.0		0.1	Emission Factors
			SO2		0.06		0.006	Emission Factors
			Pb		3.83E-04		3.83E-05	Emission Factors
			Total HAP		7.27E-02		7.27E-03	Emission Factors
			CO2e		4,473		447.3	Emission Factors
FWP	Tier 3	FWP	NOx		2.3		0.6	Emission Factors
			CO		2.0		0.5	Emission Factors
			VOC		2.3		0.6	Emission Factors
			Total PM		0.1		0.03	Emission Factors
			Total PM10		0.1		0.03	Emission Factors
			Total PM2.5		0.1		0.03	Emission Factors
			SO2		0.004		0.0011	Emission Factors
			Pb		2.90E-05		7.25E-06	Emission Factors
			Total HAP		1.03E-02		2.57E-03	Emission Factors
			CO2e		338.7		84.7	Emission Factors

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions [a] (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission [b] (tpy)	Method of Determination
TNK	Submerged fill	N/A	VOC		0.7		3.1	AP-42
			Total HAP		0.1		0.4	AP-42
WBH2 WBH3 WBH4	Ultra low-NOx	STW2 STW3 STW4	NOx		0.10		1.3	9 ppmvd @ 3%O_2
			CO		0.37		9.7	100 ppmvd @ 3%O_2
			VOC		0.05		1.3	20 ppmvd @ 3%O_2
			Total PM		0.07		1.0	Emission Factors
			Total PM10		0.07		1.0	Emission Factors
			Total PM2.5		0.07		1.0	Emission Factors
			SO2		0.01		0.2	0.5 gr S per 100 scf
			Pb		4.91E-06		6.45E-05	Emission Factors
			Total HAP		0.02		0.2	Emission Factors
			CO2e		3,513		15,387	Emission Factors

[a] Hourly Potential Emissions for CT8-10 (Units 8-10) and WBH2-4 are for each emission unit and based on the Design Capacity provided in SIP Form 2.01.
[b] Potential Annual CT8-10 (Units 8-10) and WBH2-4 are for the emission units, combined, based on Potential Annual Fuel Consumption provided in SIP Form 2.01, and, for CT8-10 (Units 8-10) include startup and shutdown emissions.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
CT8 (Unit 8)	Combustion Turbine Unit 8	NOx/CO		Continuous
CT9 (Unit 9)	Combustion Turbine Unit 9	NOx/CO		Continuous
CT10 (Unit 10)	Combustion Turbine Unit 10	NOx/CO		Continuous

Comments:

Please refer to the CAM plans provided in Appendix D.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
ST8	CT8	See NOTE.		Towards the sky	88	255	See NOTE.			
ST9	CT9			Towards the sky	88	255				
ST10	CT10			Towards the sky	88	255				
EDG	EDG			Towards the sky	NA	NA				
FWP	FWP			Towards the sky	NA	NA				
STW2	WBH2			Other (capped)	NA	NA				
STW3	WBH3			Other (capped)	NA	NA				
STW4	WBH4			Other (capped)	NA	NA				

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

Stack Information and Exit Gas Conditions at Maximum Emissions Rate are provided in the accompanying application for Combustion Turbine Units 8, 9, and 10 in Tables 6-2, 6-3, 6-4, and 6-5 and for the emergency generator, fire water pump engine, and fuel gas heaters in Table 6-8.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Facility Name: Yates Steam-Electric Generating Plant **Date of Application:** December 2023

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
Please refer to Section 10 of the accompanying application.				☐
				☐
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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

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)
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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).

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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

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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

Facility (Source) Name (from STEP 1) Yates (728)

any other provision of the Act, including the provisions of title I of the Act relating

STEP 3, Cont'd.

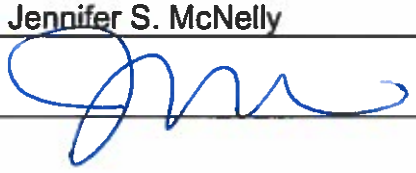
Effect on Other Authorities, Cont'd.

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 Jennifer S. McNelly	
Signature 	Date 12/7/23

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Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

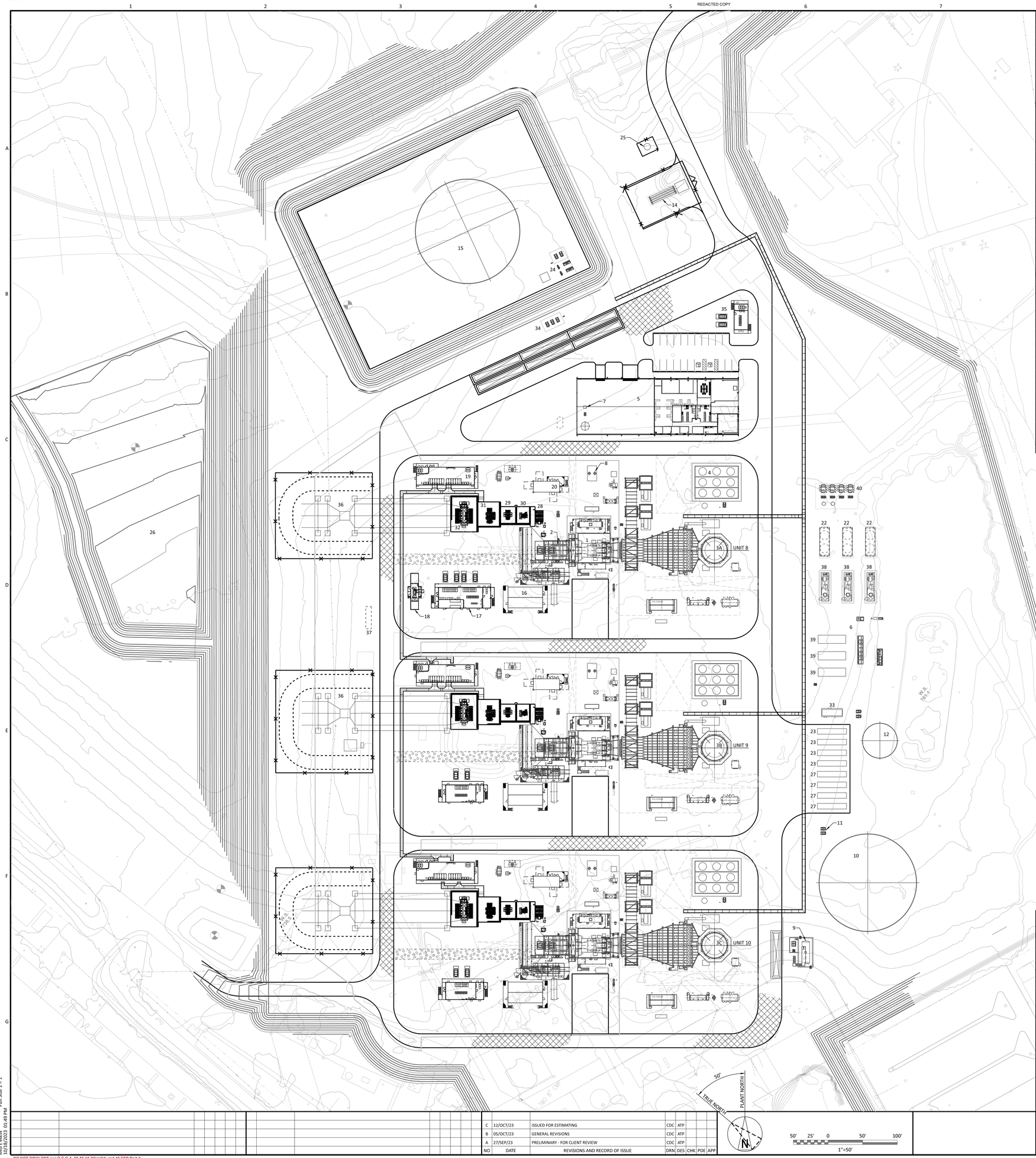
DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

STF-PIA-10-9 Attachment

Appendix B

Plot Plan

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FACILITIES LEGEND

ID	FACILITY	ARRANGEMENT	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
1	GAS TURBINE (GT)	-	-	-	
2	GENERATOR	-	-	-	
3	SCR STACK	-	-	-	
4	AIR COOLED HEAT EXCHANGER	-	-	-	
5	ADMINISTRATION / CONTROL BUILDING	-	-	-	
6	GAS YARD	-	-	-	
7	POTABLE WATER TEMPERING SKID	-	-	-	
8	GT FUEL GAS INLET FILTER	-	-	-	
9	AMMONIA STORAGE TANK	-	-	-	
10	DEMIN WATER STORAGE TANK	-	-	-	
11	DEMIN PUMPS	-	-	-	
12	SERVICE/FIRE WATER STORAGE TANK	-	-	-	
13	PLANT PARKING	-	-	-	
14	HYDROGEN STORAGE TUBES	-	-	-	
15	FUEL OIL STORAGE TANK	-	-	-	
16	GT CONTROL MODULE	-	-	-	
17	LOW VOLTAGE ECLECTRICAL PDC	-	-	-	
18	STANDBY DIESEL GENERATOR	-	-	-	
19	MEDIUM VOLTAGE ELECTRICAL PDC	-	-	-	
20	CTG EXCITATION / SFC CUBICLE PACKAGE	-	-	-	
21	SWITCHYARD	-	-	-	
22	FUEL GAS COMPRESSOR COOLER	-	-	-	
23	DEMINERALIZED WATER TREATMENT TRAILERS	-	-	-	
24	FUEL OIL PUMP & FILTERS	-	-	-	
25	CO2 STORAGE	-	-	-	
26	STORMWATER	-	-	-	
27	FILTERED WATER TREATMENT TRAILERS	-	-	-	
28	GENERATOR BREAKER	-	-	-	
29	SFC TRANSFORMER	-	-	-	
30	GTG EXCITATION TRANSFORMER	-	-	-	
31	UNIT AUX TRANSFORMER	-	-	-	
32	GENERATOR STEP-UP (GSU) TRANSFORMER	-	-	-	
33	FIRE PROTECTION PUMP ENCLOSURE	-	-	-	
34	FUEL OIL TRUCK UNLOADING PUMPS	-	-	-	
35	POWER DISTRIBUTION CENTER (PDC)	-	-	-	
36	TRANSMISSION CORRIDOR	-	-	-	
37	OIL/WATER SEPARATOR (BELOW GRADE)	-	-	-	
38	FUEL GAS COMPRESSOR	-	-	-	
39	FUEL GAS HEATER	-	-	-	
40	AIR COMPRESSORS	-	-	-	

EMISSION POINTS

DESCRIPTION	LOCATION NORTH	LOCATION EAST
STACK (UNIT 8)	1260838.15	2071928.73
STACK (UNIT 9)	1260654.96	2071710.41
STACK (UNIT 10)	1260471.77	2071492.09
AMMONIA TANKS	1261234.83	2072327.65
FUEL FORWARDING SKID	1261263.87	2072143.45
EMERGENCY GENERATOR	1261131.68	2071605.10
FUEL GAS HEATER 1	1260625.79	2071939.49
FUEL GAS HEATER 2	1260610.53	2071921.30
FUEL GAS HEATER 3	1260595.26	2071903.11

GENERAL LEGEND

AGGREGATE SURFACING

ASPHALT SURFACING

CONCRETE

SEEDING

NOTES

1. THIS DRAWING IS THE BASIS FOR THE SITE ARRANGEMENT AND IS SUBJECT TO REVISIONS AS A RESULT OF DETAILED DESIGN AND DUE TO VARIATIONS IN SUPPLIERS OF MAJOR EQUIPMENT.
2. COORDINATES INDICATED ON THIS DRAWING ARE IN NAD83 STATE PLANE - GEORGIA WEST, US SURVEY FEET.

OPEN
10/18/2023

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
C	12/OCT/23	ISSUED FOR ESTIMATING	CDC	ATP			
B	05/OCT/23	GENERAL REVISIONS	CDC	ATP			
A	27/SEP/23	PRELIMINARY - FOR CLIENT REVIEW	CDC	ATP			

50' 25' 0 50' 100'
1"=50'

GEORGIA POWER COMPANY
PROJECT PEREGRINE - YATES UNITS 8, 9, & 10
SITE ARRANGEMENT

PROJECT P241653-3GAU-S1001 | DRAWING NUMBER | REV C

DESIGNER ATP | DRAWN CDC | CHECKED | DATE | CODE | AREA

MicroStation v10.15.0.74
Full Size 1 = 1
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DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

STF-PIA-10-9 Attachment

Appendix C

Emission Calculations

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Georgia Power Company

Combustion Turbine Units 8, 9, and 10

Table C-1

Emissions Calculations - Gas Firing

Maximum Heat Input (HHV) 4,083 MMBtu/hr

Annual Average Heat Input (HHV) 3,984 MMBtu/hr

	Summary of Short Term Emission Rates (lb/hr/unit)												
	TSP[4/5]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Maximum hourly operating emission rates [1/2]	7.02	24.47	24.47	41.0	35.0	11.40	5.72	8.76	0.00200	485,289	10	1	485,832
Annual average hourly operating emission rates [2/3]	6.95	23.90	23.90	40.0	35.0	11.20	5.58	8.55	0.00195	473,523	10	1	474,052
	Summary of Annual Emission Rates, Normal Operations (tpy/unit)												
Full Load Operation @ Permit Capacity Factor	12.63	43.44	43.44	72.71	63.62	20.36	10.15	15.54	0.0036	860,722	17.56	1.76	861,684

	Summary of Combustion Turbine Worst-Case Annual Emission Totals (facility tons/yr)												
	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
Worst-Case Annual Emissions [6]	43.6	131.3	131.3	293.0	946.1	301.9	30.4	46.61	0.0107				2,585,053

	Assessment of combustion turbine worst-case annual emission totals (facility ton/yr)												
	TSP	PM10	PM2.5	NOx	CO	VOC	SO2	H2SO4	Lead	CO2	CH4	N2O	CO2e
1. Full Load Operation @ Permit Capacity Factor	37.90	130.31	130.31	218.12	190.86	61.07	30.44	46.61	0.01066	2,582,166	53	5	2,585,053
2. Accounting for SU/SD hours	Annual hours breakdown: startup: 160 shutdown: 25 operating: 3,450												
a. Startup Emissions	6.30	6.30	6.30	75.60	571.50	199.80	0.65	0.99	0.00023	55,090	1.1	0.11	55,151
b. Shutdown Emissions	1.35	1.35	1.35	10.35	193.50	44.10	0.09	0.14	0.00003	8,023	0.16	0.02	8,032
c. Operating Emissions	35.97	123.68	123.68	207.02	181.15	57.97	28.89	44.24	0.01012	2,450,763	50.00	5.00	2,453,504
Total Emissions	**43.62**	**131.33**	**131.33**	**292.97**	**946.15**	**301.87**	**29.63**	**45.38**	**0.01038**				**2,516,687**

1/ Maximum short term PM, NOx, CO and VOC emission rates are from the 100% load at 20ºF ambient temperature case.

2/ Emission rates for lead, CO2, CH4 and N2O are calculated using emission factors from AP-42 Table 1.4-2 (Pb), 40 CFR Part 75, Appendix G, Sec. 2.3 (CO2) and 40 CFR Part 98 Table C-2 (CH4 and N2O).

3/ Annual average PM, NOx, CO and VOC emission rates are from the 100% load at 59ºF ambient temperature case.

4/ All FPM assumed to be < 10 microns; PM2.5 = PM10

5/ Short term and annual average TSP and PM10 emission rates are estimated at the expected maximum gas sulfur content

6/ Worst-case emissions determined during normal operation for permited capacity factor hours per year or operations with expected startup/shutdown times.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Georgia Power Company

Combustion Turbine Units 8, 9, and 10

Table C-2

Emissions Calculations - Oil Firing

Maximum Heat Input (HHV) 3,447 MMBtu/hr

Annual Average Heat Input (HHV) 3,446 MMBtu/hr

	TSP[4/5]	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of Short Term Emission Rates (lb/hr/unit)												
Maximum hourly operating emission rates [1/2]	35.36	48.51	48.51	74.0	45.0	10.3	5.27	8.08	0.04826	559,394	23	5	561,322
Annual average hourly operating emission rates [2/3]	35.36	48.51	48.51	74.0	45.0	10.3	5.27	8.07	0.04824	559,231	23	5	561,160
	Summary of Annual Emission Rates, Normal Operations (tpy/unit)												
Full Load Operation @ Permit Capacity Factor	64.27	88.18	88.18	134.51	81.80	18.72	9.58	14.68	0.088	1,016,515	41.43	8.29	1,020,020

	TSP	PM_{10}	$PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2SO_4	Lead	CO_2	CH_4	N_2O	CO_2e
	Summary of Combustion Turbine Worst-Case Annual Emission Totals (facility tons/yr)												
Worst-Case Annual Emissions [6]	251.0	316.4	316.4	504.8	3013.8	1041.2	28.8	44.03	0.2631				3,060,060

	TSP	PM10	PM2.5	NOx	CO	VOC	SO2	H2SO4	Lead	CO2	CH4	N2O	CO2e
	Assessment of combustion turbine worst-case annual emission totals (facility ton/yr)												
1. Full Load Operation @ Permit Capacity Factor	192.81	264.55	264.55	403.53	245.39	56.17	28.75	44.03	0.26308	3,049,545	124	25	3,060,060
2. Accounting for SU/SD hours				Annual hours breakdown: startup: 245	shutdown: 75	operating: 3,315							
a. Startup Emissions	43.65	43.65	43.65	103.50	2025.00	765.00	0.93	1.42	0.00851	98,588	4.02	0.80	98,928
b. Shutdown Emissions	31.50	31.50	31.50	33.30	765.00	225.00	0.26	0.40	0.00239	27,751	1.13	0.23	27,846
c. Operating Emissions	175.84	241.26	241.26	368.01	223.79	51.22	26.22	40.16	0.23992	2,781,114	113.34	22.67	2,790,703
Total Emissions	**250.99**	**316.41**	**316.41**	**504.81**	**3013.79**	**1041.22**	**27.41**	**41.98**	**0.25082**				**2,917,477**

1/ Maximum short term PM, NOx, CO and VOC emission rates are from the 100% load at 20ºF ambient temperature case.

2/ Emission rates for lead, CO2, CH4 and N2O are calculated using emission factors from AP-42 Table 3.1-2a, 40 CFR Part 75, Appendix G, Sec. 2.3 (CO2) and 40 CFR Part 98 Table C-2 (CH4 and N2O).

3/ Annual average PM, NOx, CO and VOC emission rates are from the 100% load at 59ºF ambient temperature case.

4/ All FPM assumed to be < 10 microns; PM2.5 = PM10

5/ Short term and annual average TSP and PM10 emission rates are estimated at the expected maximum gas sulfur content

6/ Worst-case emissions determined during normal operation for permited capacity factor hours per year or operations with expected startup/shutdown times.

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Combustion Turbine Data - Natural Gas Firing
Table C-3
Operating and Emissions Data for CT

List for each operating condition varying ambient T, RH.

Parameter	Units																													annual average	max hourly
CT Load	%	105 ºF	100% - EC	100%	75%	MECL	95 ºF	100% - EC	100%	75%	MECL	65 ºF	100% - EC	100%	75%	MECL	59 ºF	100% - EC	100%	75%	MECL	40 ºF	100%	75%	MECL	20 ºF	100%	75%	MECL	0 ºF	100%	75%	MECL	100%	100%
Ambient Pressure	psia		14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302		14.302	14.302	14.302		14.302	14.302	14.302		
Ambient Temp	°F		105	105	105	105		95	95	95	95		65	65	65	65		59	59	59	59		40	40	40		20	20	20		0	0	0	59	20
Relative Humidity	%		30	30	30	30		45	45	45	45		75	75	75	75		60	60	60	60		75	75	75		75	75	75		75	75	75	60	75
Fuel Type			Gas	Gas	Gas	Gas		Gas	Gas	Gas	Gas		Gas	Gas	Gas	Gas		Gas	Gas	Gas	Gas		Gas	Gas	Gas		Gas	Gas	Gas		Gas	Gas	Gas	Gas	Gas
Evap Cooler Status	On/Off		ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		OFF	OFF	OFF		OFF	OFF	OFF		OFF	OFF	OFF		
NG Supply																																			
CH4	% mol		95.296	95.296	95.296	95.296		95.296	95.296	95.296	95.296		95.296	95.296	95.296	95.296		95.296	95.296	95.296	95.296		95.296	95.296	95.296		95.296	95.296	95.296		95.296	95.296	95.296	95	95
C2H6	% mol		2.866	2.866	2.866	2.866		2.866	2.866	2.866	2.866		2.866	2.866	2.866	2.866		2.866	2.866	2.866	2.866		2.866	2.866	2.866		2.866	2.866	2.866		2.866	2.866	2.866	2.866	2.866
C3H8	% mol		0.160	0.160	0.160	0.160		0.160	0.160	0.160	0.160		0.160	0.160	0.160	0.160		0.160	0.160	0.160	0.160		0.160	0.160	0.160		0.160	0.160	0.160		0.160	0.160	0.160	0.160	0.160
n-C4H10	% mol		0.019	0.019	0.019	0.019		0.019	0.019	0.019	0.019		0.019	0.019	0.019	0.019		0.019	0.019	0.019	0.019		0.019	0.019	0.019		0.019	0.019	0.019		0.019	0.019	0.019	0.019	0.019
i-C4H10	% mol		0.017	0.017	0.017	0.017		0.017	0.017	0.017	0.017		0.017	0.017	0.017	0.017		0.017	0.017	0.017	0.017		0.017	0.017	0.017		0.017	0.017	0.017		0.017	0.017	0.017	0.017	0.017
n-C5H12	% mol		0.010	0.010	0.010	0.010		0.010	0.010	0.010	0.010		0.010	0.010	0.010	0.010		0.010	0.010	0.010	0.010		0.010	0.010	0.010		0.010	0.010	0.010		0.010	0.010	0.010	0.010	0.010
C6H14	% mol		0.007	0.007	0.007	0.007		0.007	0.007	0.007	0.007		0.007	0.007	0.007	0.007		0.007	0.007	0.007	0.007		0.007	0.007	0.007		0.007	0.007	0.007		0.007	0.007	0.007	0.007	0.007
N2	% mol		0.537	0.537	0.537	0.537		0.537	0.537	0.537	0.537		0.537	0.537	0.537	0.537		0.537	0.537	0.537	0.537		0.537	0.537	0.537		0.537	0.537	0.537		0.537	0.537	0.537	0.537	0.537
CO2	% mol		1.088	1.088	1.088	1.088		1.088	1.088	1.088	1.088		1.088	1.088	1.088	1.088		1.088	1.088	1.088	1.088		1.088	1.088	1.088		1.088	1.088	1.088		1.088	1.088	1.088	1.088	1.088
S	grains per 100 SCF		0.5	0.5	0.5	0.5		0.5	0.5	0.5	0.5		0.5	0.5	0.5	0.5		0.5	0.5	0.5	0.5		0.5	0.5	0.5		0.5	0.5	0.5		0.5	0.5	0.5	0.5	0.5
NG Molecular Weight	lb/lbmol		16.8836	16.8836	16.8836	16.8836		16.8836	16.8836	16.8836	16.8836		16.8836	16.8836	16.8836	16.8836		16.8836	16.8836	16.8836	16.8836		16.8836	16.8836	16.8836		16.8836	16.8836	16.8836		16.8836	16.8836	16.8836	16.8836	16.8836
Fuel LHV	BTU/lb		20,644	20,644	20,644	20,644		20,644	20,644	20,644	20,644		20,644	20,644	20,644	20,644		20,644	20,644	20,644	20,644		20,644	20,644	20,644		20,644	20,644	20,644		20,644	20,644	20,644	20,644	20,644
Fuel HHV	BTU/lb		22,907	22,907	22,907	22,907		22,907	22,907	22,907	22,907		22,907	22,907	22,907	22,907		22,907	22,907	22,907	22,907		22,907	22,907	22,907		22,907	22,907	22,907		22,907	22,907	22,907	22,907	22,907
Fuel LHV	BTU/scf		919	919	919	919		919	919	919	919		919	919	919	919		919	919	919	919		919	919	919		919	919	919		919	919	919	919	919
Fuel HHV	BTU/scf		1,019	1,019	1,019	1,019		1,019	1,019	1,019	1,019		1,019	1,019	1,019	1,019		1,019	1,019	1,019	1,019		1,019	1,019	1,019		1,019	1,019	1,019		1,019	1,019	1,019	1,019	1,019
NG to the CT																																			
NG Heat Input	MMBtu/hr - HHV		3,849	3,472	2,847	2,295		3,862	3,639	2,913	2,353		3,978	3,946	3,083	2,387		4,014	3,984	3,109	2,403		4,054	3,183	2,453		4,083	3,339	2,528		4,003	3,458	2,723	3,984	4,083
NG Heat Input	MMBtu/hr - LHV		3,469	3,129	2,566	2,068		3,481	3,279	2,625	2,121		3,585	3,556	2,778	2,151		3,618	3,590	2,802	2,166		3,654	2,869	2,210		3,680	3,009	2,278		3,608	3,117	2,454	3,618	3,680
NG temperature at the CT inlet	(ºF)		392	392	392	392		392	392	392	392		392	392	392	392		392	392	392	392		392	392	392		392	392	392		392	392	392	392	392
Flow Rate	lb/hr		168,025	151,558	124,282	100,163		168,589	158,825	127,141	102,695		173,618	172,247	134,554	104,177		175,223	173,888	135,681	104,893		176,962	138,952	107,052		178,225	145,731	110,321		174,726	150,947	118,852	175,223	178,225
Stack Exit Conditions (GT post controls)																																			
Exhaust Flow	lb/hr		10,205,000	9,676,000	8,773,000	7,811,000		10,221,000	9,926,000	8,842,000	7,914,000		10,398,000	10,369,000	9,067,000	7,921,000		10,433,000	10,433,000	9,114,000	7,942,000		10,458,000	9,191,000	7,989,000		#########	9,520,000	8,105,000		#########	9,672,000	8,410,000		
Exhaust Flow	ACFM		5,771,354	5,398,526	4,739,730	4,150,472		5,764,973	5,551,541	4,766,787	4,221,569		5,796,288	5,773,155	4,830,339	4,168,258		5,797,579	5,789,408	4,835,081	4,164,414		5,795,411	4,870,701	4,183,471		5,773,274	5,037,263	4,232,893		5,675,227	5,120,858	4,395,117		
Exhaust Flow	DSCFM		2,098,780	2,002,276	1,824,210	1,631,759		2,102,258	2,049,564	1,835,761	1,650,910		2,149,317	2,145,158	1,886,196	1,656,658		2,160,034	2,162,713	1,899,519	1,663,886		2,169,947	1,917,105	1,674,938		2,175,690	1,987,347	1,700,332		2,152,194	2,018,606	1,762,608		
Oxygen	% volume		14.39	14.79	15.37	15.89		14.38	14.64	15.26	15.81		14.46	14.51	15.19	15.84		14.48	14.55	15.23	15.87		14.50	15.18	15.83		14.50	15.15	15.79		14.58	15.05	15.61		
Carbon Dioxide	% volume		2.86	2.73	2.48	2.24		2.87	2.79	2.51	2.27		2.91	2.90	2.60	2.31		2.93	2.91	2.60	2.32		2.96	2.65	2.35		2.98	2.68	2.39		2.95	2.73	2.48		
Water	% volume		7.44	6.62	6.03	5.45		7.42	6.90	6.24	5.64		6.68	6.57	5.91	5.24		6.44	6.26	5.61	4.99		6.12	5.48	4.86		5.94	5.35	4.76		5.77	5.35	4.85		
Nitrogen	% volume		74.39	74.94	75.20	75.49		74.41	74.76	75.07	75.35		75.03	75.09	75.39	75.69		75.22	75.34	75.62	75.89		75.50	75.77	76.02		75.65	75.89	76.13		75.76	75.93	76.12		
Argon	% volume		0.92	0.92	0.92	0.93		0.92	0.92	0.92	0.92		0.92	0.92	0.93	0.93		0.93	0.93	0.93	0.93		0.93	0.93	0.93		0.93	0.93	0.93		0.93	0.93	0.93		
Molecular Weight	lb/lbmol		28.41	28.49	28.53	28.57		28.41	28.46	28.51	28.55		28.50	28.51	28.55	28.60		28.53	28.54	28.59	28.63		28.56	28.60	28.65		28.59	28.62	28.66		28.60	28.63	28.66		
Exhaust Gas Temperature	F		825	811	773	754		822	813	769	758		811	809	757	744		808	807	753	741		806	752	740		800	751	737		795	752	738		
Exhaust Gas Stack Velocity	ft/sec		89.46	83.68	73.47	64.34		89.36	86.05	73.89	65.44		89.85	89.49	74.87	64.61		89.87	89.74	74.95	64.55		89.83	75.50	64.85		89.49	78.08	65.61		87.97	79.38	68.13		
Exhaust Gas Density	lb/ft3		0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03		0.03	0.03	0.03		0.03	0.03	0.03		
Stack Height	ft		187	187	187	187		187	187	187	187		187	187	187	187		187	187	187	187		187	187	187		187	187	187		187	187	187		
Stack Diameter	ft		37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0		37.0	37.0	37.0		37.0	37.0	37.0		
Stack Emissions (Emissions After Control)																																			
NOx	ppmvd @ 15% O2		2.5	2.5	2.5	2.5		2.5	2.5	2.5	2.5		2.5	2.5	2.5	2.5		2.5	2.5	2.5	2.5		2.5	2.5	2.5		2.5	2.5	2.5		2.5	2.5	2.5	2.5	2.5
NOx	lb/hr		39.0	35.0	29.0	23.0		39.0	37.0	29.0	24.0		40.0	40.0	31.0	24.0		40.0	40.0	31.0	24.0		41.0	32.0	25.0		41.0	34.0	26.0		40.0	35.0	27.0	40	41
NOx	lb/MMBtu -HHV		0.00993	0.00993	0.00992	0.00992		0.00993	0.00993	0.00993	0.00991		0.00993	0.00993	0.00992	0.00991		0.00993	0.00992	0.00992	0.00991		0.00993	0.00993	0.00992		0.00993	0.00992	0.00991		0.00993	0.00993	0.00991	0.00992	0.00993
CO	ppmvd @ 15% O2		3.5	3.5	3.5	3.5		3.5	3.5	3.5	3.5		3.5	3.5	3.5	3.5		3.5	3.5	3.5	3.5		3.5	3.5	3.5		3.5	3.5	3.5		3.5	3.5	3.5	2.0	2.0
CO	lb/hr		33.3	29.8	24.5	21.0		33.3	31.5	26.3	21.0		35.0	35.0	26.3	21.0		35.0	35.0	28.0	21.0		35.0	28.0	21.0		35.0	29.8	22.8		35.0	29.8	24.5	35.0	35.0
CO	lb/MMBtu -HHV		0.00864	0.00857	0.00861	0.00915		0.00861	0.00866	0.00901	0.00892		0.00880	0.00887	0.00851	0.00880		0.00872	0.00879	0.00901	0.00874		0.00863	0.00880	0.00856		0.00857	0.00891	0.00900		0.00874	0.00860	0.00900	0.00879	0.00857
SO2	lb/hr		5.4	4.9	4.0	3.2		5.4	5.1	4.1	3.3		5.6	5.5	4.3	3.3		5.6	5.6	4.4	3.4		5.7	4.5	3.4		5.7	4.7	3.5		5.6	4.8	3.8	5.6	5.7
SO2	lb/MMBtu -HHV		0.00140	0.00140	0.00140	0.00140		0.00140	0.00140	0.00140	0.00140		0.00140	0.00140	0.00140	0.00140		0.00140	0.00140	0.00140	0.00140		0.00140	0.00140	0.00140		0.00140	0.00140	0.00140		0.00140	0.00140	0.00140	0.00140	0.00140
H2SO4	lb/hr		8.3	7.4	6.1	4.9		8.3	7.8	6.3	5.0		8.5	8.5	6.6	5.1		8.6	8.5	6.7	5.2		8.7	6.8	5.3		8.8	7.2	5.4		8.6	7.4	5.8	8.6	8.8
H2SO4	lb/MMBtu -HHV		0.00215	0.00215	0.00215	0.00215		0.00215	0.00215	0.00215	0.00215		0.00215	0.00215	0.00215	0.00215		0.00215	0.00215	0.00215	0.00215		0.00215	0.00215	0.00215		0.00215	0.00215	0.00215		0.00215	0.00215	0.00215	0.00215	0.00215
VOC	ppmvd @ 15% O2		2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0		2.0	2.0	2.0		2.0	2.0	2.0	2.0	2.0
VOC	lb/hr		10.8	9.8	8.0	6.4		10.8	10.2	8.2	6.6		11.2	11.0	8.6	6.6		11.2	11.2	8.6	6.8		11.4	9.0	6.8		11.4	9.4	7.0		11.2	9.6	7.6	11.2	11.4
VOC	lb/MMBtu -HHV		0.00281	0.00282	0.00281	0.00279		0.00280	0.00280	0.00281	0.00280		0.00282	0.00279	0.00279	0.00276		0.00279	0.00281	0.00277	0.00283		0.00281	0.00283	0.00277		0.00279	0.00282	0.00277		0.00280	0.00278	0.00279	0.00281	0.00279
CO2	lb/hr		457,477	412,668	338,383	272,775		459,022	432,517	346,228	279,668		472,809	469,006	366,433	283,709		477,088	473,523	369,524	285,611		481,842	378,319	291,554		485,289	396,860	300,468		475,781	411,004	323,645	473,523	485,289
CO2	lb/MMBtu -HHV		118.856	118.856	118.856	118.856		118.856	118.856	118.856	118.856		118.856	118.856	118.856	118.856		118.856	118.856	118.856	118.856		118.856	118.856	118.856		118.856	118.856	118.856		118.856	118.856	118.856	118.856	118.856
PM filterable	lb/hr		6.6	6.1	5.2	4.1		6.6	6.4	5.2	4.2		6.9	6.9	5.5	4.3		6.9	7.0	5.6	4.3		7.0	5.6	4.4		7.0	6.0	4.5		6.9	6.2	4.8	7.0	7.0
PM filterable	lb/MMBtu -HHV		0.00172	0.00175	0.00181	0.00180		0.00172	0.00174	0.00179	0.00179		0.00173	0.00174	0.00178	0.00178		0.00173	0.00174	0.00179	0.00179		0.00172	0.00177	0.00177		0.00172	0.00180	0.00178		0.00172	0.00179	0.00177	0.00174	0.00172
PM10/PM.25 (Filterable + Condensable)	lb/hr		23.1	20.8	17.1	13.8		23.2	21.8	17.5	14.1		23.8	23.6	18.5	14.3		24.0	23.9	18.6	14.4		24.3	19.1	14.7		24.5	20.0	15.2		24.0	20.7	16.3	23.9	24.5
PM10/PM.25 (Filterable + Condensable)	lb/MMBtu -HHV		0.0060	0.0060	0.0060	0.0060		0.0060	0.0060	0.0060	0.0060		0.0060	0.0060	0.0060	0.0060		0.0060	0.0060	0.0060	0.0060		0.0060	0.0060	0.0060		0.0060	0.0060	0.0060		0.0060	0.0060	0.0060	0.006	0.006
Ammonia Slip	ppmvd @ 15% O2		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0	5.0	5.0
Ammonia Slip	lb/hr		28.3	25.6	21.0	16.9		28.4	26.8	21.5	17.3		29.3	29.0	22.7	17.5		29.5	29.3	22.9	17.7		29.8	23.4	18.0		30.1	24.6	18.6		29.4	25.5	20.0	29.3	30.1
Ammonia Slip	lb/MMBtu -HHV		0.00736	0.00735	0.00735	0.00735		0.00735	0.00735	0.00735	0.00734		0.00736	0.00735	0.00735	0.00734		0.00735	0.00735	0.00734	0.00734		0.00736	0.00735	0.00734		0.00735	0.00735	0.00734		0.00735	0.00735	0.00734	0.00735	0.00736
Formaldehyde	ppbvd @ 15% O2		91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0		91.0	91.0	91.0		91.0	91.0	91.0	91.0	91.0
Formaldehyde	lb/MMBtu -HHV		0.00024	0.00024	0.00024	0.00024		0.00024	0.00024	0.00024	0.00024		0.00024	0.00024	0.00024	0.00024		0.00024	0.00024	0.00024	0.00024		0.00024	0.00024	0.00024		0.00024	0.00024	0.00024		0.00024	0.00024	0.00024	0.00024	0.00024

Startup/Shutdown

Durations
Startup 32 mins
Shutdown 5 mins

Heat Input
Startup 1030 MMBtu 1,010,795 scf
Shutdown 150 MMBtu 147,203 scf

Gas Sulfur Content 0.5 gr/100 CF

Emissions	Startup		Shutdown		
NOx	168	lbs/event	23	lbs/event	
CO	1270	lbs/event	430	lbs/event	
VOC	444	lbs/event	98	lbs/event	
PM	14	lbs/event	3	lbs/event	
SO2	1.44	lbs/event	0.210	lbs/event	assume all gas sulfur produces SO2
H2SO4	2.21	lbs/event	0.322	lbs/event	assume all gas sulfur produces H2SO4 via oxidation catalyst
CO2	122,422	lbs/event	17,828	lbs/event	
CH4	2.4978118	lbs/event	0.363759	lbs/event	
N2O	0.24978118	lbs/event	0.036376	lbs/event	
lead	5.05E-04	lbs/event	7.36E-05	lbs/event	

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Combustion Turbine Data - Fuel Oil Firing
Table C-4
Operating and Emissions Data for CT

List for each operating condition varying ambient T, RH.

Parameter	Units		105 FF	100% - EC	100%	75%	MECL	95 FF	100% - EC	100%	75%	MECL	65 FF	100% - EC	100%	75%	MECL	59 FF	100% - EC	100%	75%	MECL	40 FF	100%	75%	MECL	20 FF	100%	75%	MECL	0 FF	100%	75%	MECL	100%	100%
CT Load	%																																		
Ambient Pressure	psia			14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302	14.302		14.302	14.302	14.302		14.302	14.302	14.302		14.302	14.302	14.302		
Ambient Temp	°F			105	105	105	105		95	95	95	95		65	65	65	65		59	59	59	59		40	40	40		20	20	20		0	0	0	59	20
Relative Humidity	%			30	30	30	30		45	45	45	45		75	75	75	75		60	60	60	60		75	75	75		75	75	75		75	75	75	60	75
Fuel Type				Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Evap Cooler Status	On/Off			ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		ON	OFF	OFF	OFF		OFF	OFF	OFF		OFF	OFF	OFF		OFF	OFF	OFF		
Fuel Oil Supply																																			
S	ppmwt			15	15	15	15		15	15	15	15		15	15	15	15		15	15	15	15		15	15	15		15	15	15		15	15	15	15.0	15.0
Fuel LHV	BTU/lb			18,360	18,360	18,360	18,360		18,360	18,360	18,360	18,360		18,360	18,360	18,360	18,360		18,360	18,360	18,360	18,360		18,360	18,360	18,360		18,360	18,360	18,360		18,360	18,360	18,360	18,360	18,360
Fuel HHV	BTU/lb			19,594	19,594	19,594	19,594		19,594	19,594	19,594	19,594		19,594	19,594	19,594	19,594		19,594	19,594	19,594	19,594		19,594	19,594	19,594		19,594	19,594	19,594		19,594	19,594	19,594	19,594	19,594
Fuel Oil to the CT																																			
Fuel Oil Heat Input	MMBtu/hr - HHV			3,319	2,987	2,507	2,197		3,331	3,132	2,560	2,269		3,440	3,411	2,719	2,414		3,446	3,446	2,747	2,433		3,446	2,822	2,492		3,447	2,927	2,574		3,386	3,073	2,656	3,446	3,447
Fuel Oil Heat Input	MMBtu/hr - LHV			3,110	2,799	2,349	2,059		3,122	2,935	2,399	2,126		3,224	3,196	2,548	2,262		3,229	3,229	2,575	2,280		3,230	2,644	2,335		3,230	2,743	2,412		3,173	2,880	2,489	3,229	3,230
Flow Rate	lb/hr			169,387	152,403	127,900	112,103		170,001	159,834	130,653	115,763		175,564	174,058	138,759	123,181		175,870	175,868	140,197	124,162		175,872	143,997	127,173		175,875	149,371	131,368		172,776	156,829	135,531	175,870	175,875
Stack Exit Conditions (GT post controls)																																			
Exhaust Flow	lb/hr			8,801,000	8,256,000	7,147,000	6,551,000		8,818,000	8,513,000	7,204,000	6,699,000		9,000,000	8,970,000	7,435,000	6,955,000		8,959,000	9,035,000	7,491,000	6,991,000		8,895,000	7,582,000	7,046,000		8,818,000	7,732,000	7,148,000		8,689,000	8,049,000	7,245,000		
Exhaust Flow	ACFM			4,873,399	4,554,934	4,001,142	3,688,632		4,815,851	4,689,021	4,016,244	3,759,100		4,915,910	4,895,495	4,088,770	3,846,547		4,876,021	4,913,772	4,104,449	3,850,412		4,825,536	4,140,682	3,871,989		4,772,822	4,208,610	3,916,877		4,698,535	4,364,114	3,962,234		
Exhaust Flow	DSCFM			1,782,964	1,684,142	1,461,285	1,343,394		1,786,412	1,732,311	1,470,287	1,371,541		1,833,987	1,829,854	1,521,093	1,427,458		1,829,082	1,847,551	1,535,930	1,437,839		1,820,653	1,556,008	1,450,351		1,806,993	1,587,552	1,472,181		1,782,328	1,652,957	1,491,469		
Oxygen	% volume			13.71	14.11	14.32	14.61		13.71	13.96	14.21	14.52		13.80	13.86	14.13	14.47		13.82	13.90	14.17	14.52		13.84	14.13	14.46		13.84	14.06	14.39		13.88	14.02	14.29		
Carbon Dioxide	% volume			3.92	3.78	3.66	3.51		3.93	3.84	3.71	3.54		3.99	3.97	3.83	3.63		4.02	3.99	3.84	3.65		4.05	3.90	3.71		4.09	3.97	3.78		4.09	4.01	3.85		
Water	% volume			8.82	7.92	7.64	7.31		8.80	8.22	7.87	7.53		7.94	7.81	7.47	7.12		7.66	7.46	7.14	6.80		7.28	6.99	6.65		7.09	6.87	6.54		6.95	6.82	6.56		
Nitrogen	% volume			72.65	73.29	73.48	73.67		72.66	73.07	73.31	73.51		73.35	73.45	73.66	73.87		73.59	73.74	73.93	74.12		73.90	74.07	74.26		74.06	74.18	74.37		74.16	74.23	74.38		
Argon	% volume			0.90	0.90	0.91	0.91		0.90	0.90	0.91	0.91		0.91	0.91	0.91	0.91		0.91	0.91	0.91	0.91		0.92	0.91	0.91		0.92	0.92	0.92		0.92	0.92	0.92		
Molecular Weight	lb/lbmol			28.41	28.50	28.51	28.53		28.42	28.47	28.49	28.51		28.52	28.53	28.55	28.57		28.55	28.57	28.59	28.60		28.60	28.61	28.63		28.62	28.63	28.65		28.64	28.64	28.65		
Exhaust Gas Temperature	F			798	797	817	825		781	794	811	820		786	785	796	804		783	783	793	800		781	790	798		779	787	795		778	782	793		
Exhaust Gas Stack Velocity	ft/sec			75.54	70.61	62.02	57.18		74.65	72.68	62.26	58.27		76.20	75.88	63.38	59.62		75.58	76.17	63.62	59.68		74.80	64.18	60.02		73.98	65.24	60.71		72.83	67.65	61.42		
Exhaust Gas Density	lb/ft3			0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03	0.03		0.03	0.03	0.03		0.03	0.03	0.03		0.03	0.03	0.03		
Stack Height	ft			187	187	187	187		187	187	187	187		187	187	187	187		187	187	187	187		187	187	187		187	187	187		187	187	187		
Stack Diameter	ft			37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0	37.0		37.0	37.0	37.0		37.0	37.0	37.0		37.0	37.0	37.0		
Stack Emissions (Emissions After Control)																																			
NOx	ppmvd @ 15% O2			5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0	5	5
NOx	lb/hr			72.0	64.0	54.0	47.0		72.0	67.0	55.0	49.0		74.0	73.0	59.0	52.0		74.0	74.0	59.0	53.0		74.0	61.0	54.0		74.0	63.0	56.0		73.0	66.0	57.0	74	74
NOx	lb/MMBtu -HHV			0.02141	0.02139	0.02140	0.02139		0.02139	0.02140	0.02140	0.02140		0.02140	0.02140	0.02141	0.02142		0.02141	0.02141	0.02142	0.02140		0.02143	0.02140	0.02143		0.02140	0.02140	0.02140		0.02139	0.02139	0.02141	0.02141	0.02143
CO	ppmvd @ 15% O2			5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0	5	5
CO	lb/hr			44.0	39.0	33.0	29.0		44.0	41.0	34.0	30.0		45.0	45.0	36.0	32.0		45.0	45.0	36.0	32.0		45.0	37.0	33.0		45.0	39.0	34.0		45.0	41.0	35.0	45	45
CO	lb/MMBtu -HHV			0.01303	0.01302	0.01303	0.01302		0.01303	0.01303	0.01303	0.01303		0.01303	0.01303	0.01304	0.01304		0.01304	0.01304	0.01305	0.01303		0.01305	0.01303	0.01305		0.01303	0.01303	0.01303		0.01303	0.01303	0.01303	0.01304	0.01305
SO2	lb/hr			5.1	4.6	3.8	3.4		5.1	4.8	3.9	3.5		5.3	5.2	4.2	3.7		5.3	5.3	4.2	3.7		5.3	4.3	3.8		5.3	4.5	3.9		5.2	4.7	4.1	5.3	5.3
SO2	lb/MMBtu -HHV			0.00153	0.00153	0.00153	0.00153		0.00153	0.00153	0.00153	0.00153		0.00153	0.00153	0.00153	0.00153		0.00153	0.00153	0.00153	0.00153		0.00153	0.00153	0.00153		0.00153	0.00153	0.00153		0.00153	0.00153	0.00153	0.00153	0.00153
H2SO4	lb/hr			7.8	7.0	5.9	5.1		7.8	7.3	6.0	5.3		8.1	8.0	6.4	5.7		8.1	8.1	6.4	5.7		8.1	6.6	5.8		8.1	6.9	6.0		7.9	7.2	6.2	8.1	8.1
H2SO4	lb/MMBtu -HHV			0.00234	0.00234	0.00234	0.00234		0.00234	0.00234	0.00234	0.00234		0.00234	0.00234	0.00234	0.00234		0.00234	0.00234	0.00234	0.00234		0.00234	0.00234	0.00234		0.00234	0.00234	0.00234		0.00234	0.00234	0.00234	0.00234	0.00234
VOC	ppmvd @ 15% O2			2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0	2.0		2.0	2.0	2.0		2.0	2.0	2.0		2.0	2.0	2.0	2	2
VOC	lb/hr			10.0	9.0	7.5	6.6		10.0	9.4	7.7	6.8		10.3	10.2	8.2	7.3		10.3	10.3	8.3	7.3		10.3	8.5	7.5		10.3	8.8	7.7		10.1	9.2	8.0	10.3	10.3
VOC	lb/MMBtu -HHV			0.00299	0.00299	0.00299	0.00299		0.00299	0.00299	0.00299	0.00299		0.00299	0.00299	0.00299	0.00299		0.00299	0.00299	0.00299	0.00299		0.00299	0.00299	0.00299		0.00299	0.00299	0.00299		0.00299	0.00299	0.00299	0.00299	0.00299
CO2	lb/hr			538,626	484,747	406,850	356,542		540,574	508,279	415,451	368,226		558,263	553,557	441,255	391,758		559,237	559,237	445,799	394,841		559,237	457,970	404,416		559,399	475,010	417,723		549,499	498,704	431,031	559,237	559,399
CO2	lb/MMBtu -HHV			162.3	162.3	162.3	162.3		162.3	162.3	162.3	162.3		162.3	162.3	162.3	162.3		162.3	162.3	162.3	162.3		162.3	162.3	162.3		162.3	162.3	162.3		162.3	162.3	162.3	162.3	162.3
PM filterable	lb/hr			33.57	31.07	24.99	21.86		33.66	32.32	25.17	22.61		34.95	34.87	26.49	24.09		34.79	35.36	26.89	24.38		34.53	27.39	24.67		34.11	28.19	25.21		33.45	29.97	25.67	35.36	35.36
	lb/MMBtu -HHV			0.0101	0.0104	0.0100	0.0099		0.0101	0.0103	0.0098	0.0100		0.0102	0.0102	0.0097	0.0100		0.0101	0.0103	0.0098	0.0100		0.0100	0.0097	0.0099		0.0099	0.0096	0.0098		0.0099	0.0098	0.0097	0.01026	0.01040
PM10/PM2.5 (Filterable + Condensable)	lb/hr			46.24	42.47	34.55	30.24		46.38	44.27	34.95	31.27		48.08	47.89	36.86	33.31		47.94	48.51	37.38	33.67		47.69	38.16	34.18		47.27	39.37	35.04		46.37	41.70	35.81	48.51	48.51
PM10/PM2.5 (Filterable + Condensable)	lb/MMBtu -HHV			0.01393	0.01422	0.01378	0.01377		0.01392	0.01414	0.01365	0.01378		0.01398	0.01404	0.01356	0.01380		0.01391	0.01408	0.01361	0.01384		0.01384	0.01352	0.01372		0.01371	0.01345	0.01361		0.01369	0.01357	0.01348	0.01408	0.01422
Ammonia Slip	ppmvd @ 15% O2			5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0		5.0	5.0	5.0	5.0	5.0
Ammonia Slip	lb/hr			26.3	23.7	19.9	17.4		26.4	24.8	20.3	18.0		27.3	27.1	21.6	19.2		27.4	27.4	21.8	19.3		27.4	22.4	19.8		27.3	23.2	20.4		26.9	24.4	21.1	27.4	27.4
Ammonia Slip	lb/MMBtu -HHV			0.00793	0.00792	0.00793	0.00792		0.00792	0.00792	0.00793	0.00793		0.00792	0.00793	0.00793	0.00793		0.00793	0.00793	0.00793	0.00793		0.00794	0.00792	0.00794		0.00792	0.00793	0.00793		0.00792	0.00792	0.00793	0.00793	0.00794
Formaldehyde	ppbvd @ 15% O2			91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0	91.0		91.0	91.0	91.0		91.0	91.0	91.0		91.0	91.0	91.0	91.0	91.0
Formaldehyde	lb/MMBtu -HHV			0.00026	0.00026	0.00026	0.00026		0.00026	0.00026	0.00026	0.00026		0.00026	0.00026	0.00026	0.00026		0.00026	0.00026	0.00026	0.00026		0.00026	0.00026	0.00026		0.00026	0.00026	0.00026		0.00026	0.00026	0.00026	0.00026	0.00026

Startup/Shutdown

Durations
Startup 49 mins
Shutdown 15 mins

Heat Input
Startup 1350 MMBtu 68,899 lb
Shutdown 380 MMBtu 19,394 lb

Oil Heating Value 19594 Btu/lb HHV
Oil Density 7.22 lb/gal
Oil Sulfur Content 0.0015 wt% S

Emissions	Startup		Shutdown		
NOx	230	lbs/event	74	lbs/event	
CO	4500	lbs/event	1700	lbs/event	
VOC	1700	lbs/event	500	lbs/event	
PM	97	lbs/event	70	lbs/event	
SO2	2.07	lbs/event	0.581	lbs/event	assume all gas sulfur produces SO2
H2SO4	3.163	lbs/event	0.890	lbs/event	assume all gas sulfur produces H2SO4 via oxidation catalyst
CO2	219,084	lbs/event	61,668	lbs/event	
CH4	8.92863	lbs/event	2.513244	lbs/event	
N2O	1.785726	lbs/event	0.502649	lbs/event	
lead	1.89E-02	lbs/event	5.32E-03	lbs/event	

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table C-5
Gas Heater Calculations
Annual and Maximum Hourly Emission Rates

Emission Source	Gas Fired Heater
Source Type	Natural Gas-Fired Boiler
Heat Input	<10.0 MMBtu/hr
Maximum Fuel Usage	0.01073 MMcf/hr
Number of Units	3
Natural Gas Heating Value	1,019 Btu/scf
Sulfur Content of Natural Gas	0.50 gr/100 scf
Operating Hours per Year	8,760 hr/year

Compound	Emission Factor (lb/MMBtu)	Emission Rate - per Unit		Total Units
		Hourly [c] (lb/hr)	Annual [d] (ton/year)	Annual [d] (ton/year)
Criteria Pollutants [a]				
Nitrogen Oxides	0.010	0.100	0.44	1.31
Carbon Monoxide	0.074	0.740	3.24	9.72
VOC	0.010	0.100	0.44	1.31
Sulfur Dioxide [b]	0.0014	0.014	0.061	0.18
$PM_{10}/PM_{2.5}$ [e]	0.007	0.075	0.33	0.98
Lead [e]	4.91E-07	4.9E-06	2.1E-05	6.4E-05
CO_2 [f]	116.98	1,170	5,124	15,371
CH_4 [f]	2.2E-03	2.20E-02	9.66E-02	2.90E-01
N_2O [f]	2.2E-04	2.20E-03	9.66E-03	2.90E-02
GHG Mass	116.98	1,170	5,124	15,371
CO_2e [g]	117.10	1,171	5,129	15,387

Notes:

(a) Emission Factor (lb/MMBtu) are based on vendor spec sheet.

(b) SO2 emissions are based on fuel sulfur content.

(c) Hourly emission rate (lb/hr) = heat input (MMBtu/hr) * Emission factor (lb/MMBtu)

(d) Annual emission rate (tons/year) = hourly emission rate (lb/hr) * annual operating hours (hr/year) / (2000 lb/ton)

(e) Emission factors (lb/MMBtu) are based on emission factors (lb/MMcf) referenced from AP-42, Section 1.4 dated July 1998

(f) Emission factors are based on the EPA rule "Mandatory Reporting of Greenhouse Gases", Tables C-1 & C-2.

(g) Global Warming Potentials, Federal Register Vol. 78, No. 230, November 29, 2013.

Stack Parameters

Stack Height	17	ft
Stack Diameter	2.3	ft
Stack Exit Velocity	15.0	ft/sec
Exhaust Flow	3,836	acfm
Exhaust Temp	700	°F

Vertical stack with a rain cap or similar obstruction in the exhaust system

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table C-6
Diesel Generator Calculations
Annual and Maximum Hourly Emission Rates

Emission Source:	Emergency Generator
Source Type:	Diesel-fired Emergency Generator
Engine Power (bhp)	4,699
Engine Power (kW)	3,250
Maximum Fuel Usage (gal/hr)	198.1
Heat Input (mmBtu/hr):	27.342
Fuel consumption (Btu/hphr)	5,819
Number of Units:	1
Fuel Oil Heating Value (BTU/gal)	138,000
Sulfur Content of Fuel (wt. %)	0.0015
Operating Hours per Year:	200

Compound	Emission Factor (g/hp-hr)	Emission Rates Hourly [f] (Lbs/Hr)	Emission Rates Annual [g] (Tons/Year)
Nitrogen Oxides [a]	4.4	45.27	4.53
Carbon Monoxide [a]	0.5	5.41	0.54
TOC [a]	0.2	2.32	0.23
Sulfur Dioxide [b]	0.0055	0.057	0.006
TSP [a]	0.11	1.16	0.12
PM_{10} [c]	0.10	1.07	0.11
$PM_{2.5}$ [c]	0.10	1.04	0.10
Lead [h]	3.70E-05	3.83E-04	3.8E-05
	kg/MMBtu	**(Lbs/Hr)**	**(Tons/Year)**
CO_2 [d]	73.96	4458.19	445.8
CH_4 [d]	3.00E-03	1.81E-01	1.81E-02
N_2O [d]	6.00E-04	3.62E-02	3.62E-03
GHG Mass	73.96	4,458	445.8
CO_2e [e]	74.21	4,473	447.3

Notes:

(a) Emission factors (g/hp-hr) are the NSPS Subpart IIII Tier 2 certification results for Cummins GSK95 engines.

(b) SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2

(c) Emission factors for PM10 and PM2.5 are based on speciation in AP-42 Table 3.4-2, adjusted to conform to GSK95 engine Tier 2 TSP certification.

(d) Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2.

(e) Global Warming Potentials for GHGs are from Federal Register Vol. 78, No. 230, November 29, 2013.

(f) Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

(g) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

(h) AP-42 Table 3.1-5 (4/00) Metallic HAP Emission Factors for Distillate Oil-Fired Stationary Gas Turbines.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table C-7
Diesel Fire-Water Pump Engine Calculations
Annual and Maximum Hourly Emission Rates

Emission Source:	Emergency Fire-Water Pump Engine
Source Type:	Diesel Fueled IC Reciprocating Engine
Engine Power (bhp)	350
Engine Power (kW)	261
Maximum Fuel Usage (gal/hr)	15.0
Heat Input (mmBtu/hr):	2.070
Fuel consumption (Btu/hphr)	5,914
Number of Units:	1
Fuel Oil Heating Value (BTU/gal)	138,000
Sulfur Content of Fuel (wt. %)	0.0015
Operating Hours per Year:	500

Compound	Emission Factors	Emission Rates	
		Hourly[g]	Annual[h]
	(g/hp-hr)	(Lbs/Hr)	(Tons/Year)
Nitrogen Oxides [a]	3.00	2.31	0.58
Carbon Monoxide [a]	2.60	2.01	0.50
TOC [a]	3.00	2.31	0.58
Sulfur Dioxide [b]	0.0055	0.004	0.0011
TSP [a]	0.15	0.12	0.029
PM_{10} [c]	0.14	0.11	0.027
$PM_{2.5}$ [c]	0.13	0.10	0.026
Lead [i]	3.76E-05	2.90E-05	7.2E-06
	kg/MMBtu	(Lbs/Hr)	(Tons/Year)
CO_2 [d]	73.96	337.52	84.4
CH_4 [d]	3.00E-03	1.37E-02	3.42E-03
N_2O [d]	6.00E-04	2.74E-03	6.85E-04
GHG Mass	73.96	337.54	84.4
CO_2e [e]	74.21	339	84.7

Notes:

(a) Emission factors (g/hp-hr) are the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Fire Pump Engines

(b) SO_2 emission factor from USEPA AP-42, Section 3.4, Table 3.4-1, dated October 1996, 100% conversion of fuel sulfur to SO_2

(c) Emission factors for PM10 and PM2.5 are based on speciation in AP-42 Table 3.4-2, adjusted to conform to 40 CFR 60 Subpart IIII TSP limit

(d) Emission factors for CO_2, CH_4 and N_2O are from 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting ", Tables C-1 and C-2 (amended 12/9/2016)

(e) Global Warming Potentials for GHGs are from Federal Register Vol. 78, No. 230, November 29, 2013.

(f) Hourly Emission Rate (Lbs/Hr) = (Emission Factor, g/hp-hr) * (Engine Power, hp) * (1 lb / 453.6 g)

(g) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

(h) AP-42 Table 3.1-5 (4/00) Metallic HAP Emission Factors for Distillate Oil-Fired Stationary Gas Turbines.

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Table C-8
CT Hazardous Air Pollutant Emissions - Gas Firing
Annual and Maximum Hourly Emission Rates

Pollutant	CT Emission Factor AP-42 Section 3.1-3 04/00 - Combustion Turbine Natural Gas and AP-42 Section 1.4 07/98 - Natural Gas Combustion			HAP Emissions from CTs: CT Gas Emissions: Emission Rate, 1 Turbine		HAP Emissions from CTs: CT Gas Emissions: Emission Rate, 3 CTs	
				Max Hourly[b]	Annual[c]	Max Hourly	Annual
	($lb/10^6 scf$)	(lb/MMBtu)[a]	Rating	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Metal Compounds:							
Arsenic [e]	2.00E-04	1.96E-07		8.01E-04	1.42E-03	2.40E-03	4.26E-03
Beryllium [e]	1.20E-05	1.18E-08		4.81E-05	8.53E-05	1.44E-04	2.56E-04
Cadmium [e]	1.10E-03	1.08E-06		4.41E-03	7.82E-03	1.32E-02	2.35E-02
Chromium (total) [e]	1.40E-03	1.37E-06		5.61E-03	9.95E-03	1.68E-02	2.98E-02
Cobalt [e]	8.40E-05	8.24E-08		3.37E-04	5.97E-04	1.01E-03	1.79E-03
Lead [e]	5.00E-04	4.91E-07		2.00E-03	3.55E-03	6.01E-03	1.07E-02
Manganese [e]	3.80E-04	3.73E-07		1.52E-03	2.70E-03	4.57E-03	8.10E-03
Mercury [e]	2.60E-04	2.55E-07		1.04E-03	1.85E-03	3.13E-03	5.54E-03
Nickel [e]	2.10E-03	2.06E-06		8.41E-03	1.49E-02	2.52E-02	4.48E-02
Selenium [e]	2.40E-05	2.36E-08		9.62E-05	1.71E-04	2.88E-04	5.12E-04
Organic Compounds:							
1,3-Butadiene		4.30E-07	D	1.76E-03	3.11E-03	5.27E-03	9.34E-03
Acetaldehyde		4.00E-05	C	1.63E-01	2.90E-01	4.90E-01	8.69E-01
Acrolein		6.40E-06	C	2.61E-02	4.63E-02	7.84E-02	1.39E-01
Benzene		1.20E-05	A	4.90E-02	8.69E-02	1.47E-01	2.61E-01
Ethylbenzene		3.20E-05	C	1.31E-01	2.32E-01	3.92E-01	6.95E-01
Formaldehyde[d]		2.40E-04		9.80E-01	1.74E+00	2.94E+00	5.21E+00
Naphthalene		1.30E-06	C	5.31E-03	9.41E-03	1.59E-02	2.82E-02
PAHs		2.20E-06	C	8.98E-03	1.59E-02	2.69E-02	4.78E-02
Propylene Oxide		2.90E-05	D	1.18E-01	2.10E-01	3.55E-01	6.30E-01
Toluene		1.30E-04		5.31E-01	9.41E-01	1.59E+00	2.82E+00
Xylene		6.40E-05	C	2.61E-01	4.63E-01	7.84E-01	1.39E+00

		Combustion Turbine Total (ton/yr)	**12.24**
Max Heat Input per Turbine(MMBtu/hr)	**4,083**	**Max single HAP (ton/yr)**	**5.21**
Average Heat Input per Turbine(MMBtu/hr)	**3,984**		
Total Heat Input per Turbine(MMBtu/yr)	**14,483,434**		
Natural Gas Heating Value	1,019 Btu/SCF (HHV)		

Notes:
(a) Emission Factor (lb/MMBtu) = (Emission Factor, $lb/10^6$ scf) / (Volumetric Heat Content, Btu/scf) if $lb/10^6$ scf is given.
(b) Max Hourly Emission Rate (lb/hr) = [Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)]
(c) Annual Emission Rate (ton/yr) = [Heat Input (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2000 lb/ton]
(d) Vendor-supplied emission estimate
(e) Emission Factor for natural gas from AP-42 Section 1.4 07/98 - Natural Gas Combustion.
(f) Daily emission rate (lb/day) = maximum hourly emission rate (lb/hr) * (maximum operating hours per year (hr/yr) / 365 d

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Table C-9
CT Hazardous Air Pollutant Emissions - Oil Firing
Annual and Maximum Hourly Emission Rates

Pollutant	CT Emission Factor AP-42 Section 3.1-3 04/00 - Combustion Turbine Fuel Oil and AP-42 Section 1.3 05/10 - Fuel Oil Combustion			HAP Emissions from CTs: CT Fuel Oil Emissions			
				Emission Rate, 1 Turbine		Emission Rate, 3 CTs	
	(lb/10^3 gal)	(lb/MMBtu)[a]	Rating	Max Hourly[b] (lb/hr)	Annual[c] (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Metal Compounds:							
Arsenic		1.10E-05	D	3.79E-02	6.89E-02	1.14E-01	2.07E-01
Beryllium		3.10E-07	D	1.07E-03	1.94E-03	3.21E-03	5.83E-03
Cadmium		4.80E-06	D	1.65E-02	3.01E-02	4.96E-02	9.02E-02
Chromium (total)		1.10E-05	D	3.79E-02	6.89E-02	1.14E-01	2.07E-01
Lead		1.40E-05	D	4.83E-02	8.77E-02	1.45E-01	2.63E-01
Manganese		7.90E-04	D	2.72E+00	4.95E+00	8.17E+00	1.48E+01
Mercury		1.20E-06	D	4.14E-03	7.52E-03	1.24E-02	2.25E-02
Nickel		4.60E-06	D	1.59E-02	2.88E-02	4.76E-02	8.64E-02
Selenium		2.50E-04	D	8.62E-01	1.57E+00	2.59E+00	4.70E+00
Organic Compounds:							
Benzene		5.50E-05	C	1.90E-01	3.45E-01	5.69E-01	1.03E+00
Ethylbenzene [e]	6.36E-05	4.50E-07	E	1.55E-03	2.82E-03	4.65E-03	8.45E-03
Formaldehyde[d]		2.60E-04	B	8.96E-01	1.63E+00	2.69E+00	4.89E+00
Naphthalene		3.50E-05	C	1.21E-01	2.19E-01	3.62E-01	6.58E-01
PAHs		4.00E-05		1.38E-01	2.51E-01	4.14E-01	7.52E-01
Toluene[e]	6.20E-03	4.38E-05	D	1.51E-01	2.75E-01	4.53E-01	8.24E-01
Xylene[e]	1.09E-04	7.71E-07	E	2.66E-03	4.83E-03	7.97E-03	1.45E-02

		Combustion Turbine Total (ton/yr)	**28.60**
Max Heat Input per Turbine (MMBtu/hr)	**3,447**	**Max single HAP (ton/yr)**	**14.85**
Average Heat Input per Turbine (MMBtu/hr)	**3,446**		
Total Heat Input per Turbine(MMBtu/yr)	**12,527,588**		
Fuel Oil Heating Value	19,594 Btu/lb (HHV)		

Notes:
(a) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (Volumetric Heat Content, Btu/scf) if lb/10^6 scf is given.
(b) Max Hourly Emission Rate (lb/hr) = [Max Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)]
(c) Annual Emission Rate (ton/yr) = [Heat Input (MMBtu/yr) * Emission Factor (lb/MMBtu) / 2000 lb/ton]
(d) Vendor-supplied emission estimate
(e) Emission Factor for fuel oil from AP-42 Section 1.3 05/10 - Fuel Oil Combustic

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Table C-10
Gas Heaters Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Gas Heaters		Gas Heaters	
				Emission Rate - per Heater		Emission Rate - Total	
	(lb/10^6scf)	(lb/MMBtu)[a]		Max Hourly (lb/hr)	Annual (tpy)	Max Hourly (lb/hr)	Annual (tpy)
Organic Compounds:							
Benzene	2.10E-03	2.06E-06	1	2.06E-05	9.03E-05	6.18E-05	2.71E-04
Dichlorobenzene	1.20E-03	1.18E-06	1	1.18E-05	5.16E-05	3.53E-05	1.55E-04
Formaldehyde	7.50E-02	7.36E-05	1	7.36E-04	3.22E-03	2.21E-03	9.67E-03
Hexane	1.80E+00	1.77E-03	1	1.77E-02	7.74E-02	5.30E-02	2.32E-01
Toluene	3.40E-03	3.34E-06	1	3.34E-05	1.46E-04	1.00E-04	4.38E-04
Polycyclic Organic Matter:							
2-Methylnaphthalene	2.40E-05	2.36E-08	1	2.36E-07	1.03E-06	7.07E-07	3.09E-06
3-Methylchloranthrene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1	1.57E-07	6.88E-07	4.71E-07	2.06E-06
Acenaphthene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Acenaphthylene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Anthracene	2.40E-06	2.36E-09	1	2.36E-08	1.03E-07	7.07E-08	3.09E-07
Benz(a)anthracene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Benzo(a)pyrene	1.20E-06	1.18E-09	1	1.18E-08	5.16E-08	3.53E-08	1.55E-07
Benzo(b)flouoranthene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Benzo(g,h,I)perylene	1.20E-06	1.18E-09	1	1.18E-08	5.16E-08	3.53E-08	1.55E-07
Benzo(k)fluoranthene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Chrysene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	1	1.18E-08	5.16E-08	3.53E-08	1.55E-07
Fluoranthene	3.00E-06	2.94E-09	1	2.94E-08	1.29E-07	8.83E-08	3.87E-07
Fluorene	2.80E-06	2.75E-09	1	2.75E-08	1.20E-07	8.24E-08	3.61E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	1.77E-09	1	1.77E-08	7.74E-08	5.30E-08	2.32E-07
Naphthalene	6.10E-04	5.99E-07	1	5.99E-06	2.62E-05	1.80E-05	7.87E-05
Phenanathrene	1.70E-05	1.67E-08	1	1.67E-07	7.31E-07	5.00E-07	2.19E-06
Pyrene	5.00E-06	4.91E-09	1	4.91E-08	2.15E-07	1.47E-07	6.45E-07
Metals:							
Arsenic	2.00E-04	1.96E-07	2	1.96E-06	8.60E-06	5.89E-06	2.58E-05
Beryllium	1.20E-05	1.18E-08	2	1.18E-07	5.16E-07	3.53E-07	1.55E-06
Cadmium	1.10E-03	1.08E-06	2	1.08E-05	4.73E-05	3.24E-05	1.42E-04
Chromium	1.40E-03	1.37E-06	2	1.37E-05	6.02E-05	4.12E-05	1.81E-04
Cobalt	8.40E-05	8.24E-08	2	8.24E-07	3.61E-06	2.47E-06	1.08E-05
Lead	5.00E-04	4.91E-07	3	4.91E-06	2.15E-05	1.47E-05	6.45E-05
Manganese	3.80E-04	3.73E-07	2	3.73E-06	1.63E-05	1.12E-05	4.90E-05
Mercury	2.60E-04	2.55E-07	2	2.55E-06	1.12E-05	7.65E-06	3.35E-05
Nickel	2.10E-03	2.06E-06	2	2.06E-05	9.03E-05	6.18E-05	2.71E-04
Selenium	2.40E-05	2.36E-08	2	2.36E-07	1.03E-06	7.07E-07	3.09E-06
						Total (ton/yr)	**2.44E-01**

Fuel	Gas
Number of Heaters	3
Max Heat Input (MMBtu/hr)	10
Max Operating hours per year	8760
Total Heat Input (MMBtu/yr)	87,600
Gas Heating Value (BTU/scf)	1019

1 AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-3
2 AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-4
3 AP-42 Section 1.4 07/98 - Boilers - Natural Gas Combustion Table 1.4-2

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Table C-11
Emergency Generator Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Emergency Generator	
				Emission Rate	
	Value	Units		Max Hourly (lb/hr)	Annual (tpy)
Organic Compounds:					
Acetaldehyde	2.52E-05	lb/MMBtu	1	6.89E-04	6.89E-05
Acrolein	7.88E-06	lb/MMBtu	1	2.15E-04	2.15E-05
Benzene	7.76E-04	lb/MMBtu	1	2.12E-02	2.12E-03
Formaldehyde	7.89E-05	lb/MMBtu	1	2.16E-03	2.16E-04
Toluene	2.81E-04	lb/MMBtu	1	7.68E-03	7.68E-04
Xylenes	1.93E-04	lb/MMBtu	1	5.28E-03	5.28E-04
Metals:					
Arsenic	1.10E-05	lb/MMBtu	2	3.01E-04	3.01E-05
Beryllium	3.10E-07	lb/MMBtu	2	8.48E-06	8.48E-07
Cadmium	4.80E-06	lb/MMBtu	2	1.31E-04	1.31E-05
Chromium (total)	1.10E-05	lb/MMBtu	2	3.01E-04	3.01E-05
Chromium VI		lb/MMBtu	2	0.00E+00	0.00E+00
Lead	1.40E-05	lb/MMBtu	2	3.83E-04	3.83E-05
Manganese	7.90E-04	lb/MMBtu	2	2.16E-02	2.16E-03
Mercury	1.20E-06	lb/MMBtu	2	3.28E-05	3.28E-06
Nickel	4.60E-06	lb/MMBtu	2	1.26E-04	1.26E-05
Selenium	2.50E-04	lb/MMBtu	2	6.84E-03	6.84E-04
Polycyclic Organic Matter:					
Acenaphthene	4.68E-06	lb/MMBtu	3	1.28E-04	1.28E-05
Acenaphthylene	9.23E-06	lb/MMBtu	3	2.52E-04	2.52E-05
Anthracene	1.23E-06	lb/MMBtu	3	3.36E-05	3.36E-06
Benz(a)anthracene	6.22E-07	lb/MMBtu	3	1.70E-05	1.70E-06
Benzo(b)fluoranthene	1.11E-06	lb/MMBtu	3	3.03E-05	3.03E-06
Benzo(k)fluoranthene	2.18E-07	lb/MMBtu	3	5.96E-06	5.96E-07
Benzo(g,h,i)perylene	5.56E-07	lb/MMBtu	3	1.52E-05	1.52E-06
Benzo(a)pyrene	2.57E-07	lb/MMBtu	3	7.03E-06	7.03E-07
Chrysene	1.53E-06	lb/MMBtu	3	4.18E-05	4.18E-06
Dibenzo(a,h)anthracene	3.46E-07	lb/MMBtu	3	9.46E-06	9.46E-07
Fluoranthene	4.03E-06	lb/MMBtu	3	1.10E-04	1.10E-05
Fluorene	1.28E-05	lb/MMBtu	3	3.50E-04	3.50E-05
Indo(1,2,3-cd)pyrene	4.14E-07	lb/MMBtu	3	1.13E-05	1.13E-06
Naphthalene	1.30E-04	lb/MMBtu	3	3.55E-03	3.55E-04
Phenanthrene	4.08E-05	lb/MMBtu	3	1.12E-03	1.12E-04
Pyrene	3.71E-06	lb/MMBtu	3	1.01E-04	1.01E-05
				Total (ton/yr)	**7.27E-03**

Fuel	Diesel
Horsepower (hp)	4699
Max Heat Input (MMBtu/hr)	27.34
Max Operating hours per year	200
Total Heat Input (MMBtu/yr)	5,468
Maximum Fuel Usage (gal/hr)	198.1
Fuel Oil Heating Value (BTU/gal)	138000

1 AP-42 Table 3.4-3 (10/96) Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines
2 AP-42 Table 3.1-5 (4/00) Metallic HAP Emission Factors for Distillate Oil-Fired Stationary Gas Turbines
3 AP-42 Table 3.4-4 (10/96) PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines

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Table C-12
Firewater Pump Hazardous Air Pollutant Emissions
Annual and Maximum Hourly Emission Rates

Compound Categories	Emission Factor		Emission Est. Method	Fire Water Pump	
	Value	Units		Emission Rate	
				Max Hourly (lb/hr)	Annual (tpy)
Organic Compounds:					
Acetaldehyde	7.67E-04	lb/MMBtu	1	1.59E-03	3.97E-04
Acrolein	9.25E-05	lb/MMBtu	1	1.91E-04	4.79E-05
Benzene	9.33E-04	lb/MMBtu	1	1.93E-03	4.83E-04
Butadiene, 1,3-	3.91E-05	lb/MMBtu	1	8.09E-05	2.02E-05
Formaldehyde	1.18E-03	lb/MMBtu	1	2.44E-03	6.11E-04
Toluene	4.09E-04	lb/MMBtu	1	8.47E-04	2.12E-04
Xylenes	2.85E-04	lb/MMBtu	1	5.90E-04	1.47E-04
Metals:					
Arsenic	1.10E-05	lb/MMBtu	2	2.28E-05	5.69E-06
Beryllium	3.10E-07	lb/MMBtu	2	6.42E-07	1.60E-07
Cadmium	4.80E-06	lb/MMBtu	2	9.94E-06	2.48E-06
Chromium (total)	1.10E-05	lb/MMBtu	2	2.28E-05	5.69E-06
Chromium VI		lb/MMBtu	2	0.00E+00	0.00E+00
Lead	1.40E-05	lb/MMBtu	2	2.90E-05	7.25E-06
Manganese	7.90E-04	lb/MMBtu	2	1.64E-03	4.09E-04
Mercury	1.20E-06	lb/MMBtu	2	2.48E-06	6.21E-07
Nickel	4.60E-06	lb/MMBtu	2	9.52E-06	2.38E-06
Selenium	2.50E-04	lb/MMBtu	2	5.18E-04	1.29E-04
Polycyclic Organic Matter:					
Acenaphthene	1.42E-06	lb/MMBtu	1	2.94E-06	7.35E-07
Acenaphthylene	5.06E-06	lb/MMBtu	1	1.05E-05	2.62E-06
Anthracene	1.87E-06	lb/MMBtu	1	3.87E-06	9.68E-07
Benz(a)anthracene	1.68E-06	lb/MMBtu	1	3.48E-06	8.69E-07
Benzo(b)fluoranthene	9.91E-08	lb/MMBtu	1	2.05E-07	5.13E-08
Benzo(k)fluoranthene	1.55E-07	lb/MMBtu	1	3.21E-07	8.02E-08
Benzo(g,h,i)perylene	4.89E-07	lb/MMBtu	1	1.01E-06	2.53E-07
Benzo(a)pyrene	1.88E-07	lb/MMBtu	1	3.89E-07	9.73E-08
Chrysene	3.53E-07	lb/MMBtu	1	7.31E-07	1.83E-07
Dibenzo(a,h)anthracene	5.83E-07	lb/MMBtu	1	1.21E-06	3.02E-07
Fluoranthene	7.61E-06	lb/MMBtu	1	1.58E-05	3.94E-06
Fluorene	2.92E-05	lb/MMBtu	1	6.04E-05	1.51E-05
Indo(1,2,3-cd)pyrene	3.75E-07	lb/MMBtu	1	7.76E-07	1.94E-07
Naphthalene	8.48E-05	lb/MMBtu	1	1.76E-04	4.39E-05
Phenanthrene	2.94E-05	lb/MMBtu	1	6.09E-05	1.52E-05
Pyrene	4.78E-06	lb/MMBtu	1	9.89E-06	2.47E-06
				Total (ton/yr)	**2.57E-03**

Fuel	Diesel
Horsepower (hp)	350
Max Heat Input (MMBtu/hr)	2.07
Max Operating hours per year	500
Total Heat Input (MMBtu/yr)	1,035
Maximum Fuel Usage (gal/hr)	15.0
Fuel Oil Heating Value (BTU/gal)	138000

1 AP-42 Table 3.3-2 (10/96) Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines

2 AP-42 Table 3.1-5 (4/00) Metallic HAP Emission Factors for Distillate Oil-Fired Stationary Gas Turbines

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table C-13
Storage Tank Emissions

TankSummaries_Speciated for 2024 Annual
Site: Project Peregrine,
Equations for this site: After 2019 AP-42 revisions H/D ratio: Default 0.5

																	Total loss components in the "Chosen Components" set (lbs)								
Tank ID	Diameter (ft)	Fixed Roof Type	Inside Shell Condition	Shell Condition (post-19)	Shell Finish	Roof Condition (post-19)	Roof Finish	Is Insulated	Product	RVP	Throughput (gal)	Bulk Liquid Temperature (degF)	Avg. Liquid Surface Temp. (degF)	Avg. TVP (psia)	Estimated standing losses (lbs)	Estimated working losses (lbs)	Total estimated emissions (lbs)	Benzene	Benzo(g,h,i)perylene	Ethylbenzene	Hexane (n-)	Naphthalene	PACs (Chrysene)	Toluene	Trimethylbenzene (1,2,4)	Xylene
Tank 1	150	A	L	Av	K	Av	K	N	Diesel		249370501.8	63.681929	65.012832	0.007635324	948.67855	5279.4086	6228.0872	12.67766	3.62022E-12	18.90600913	2.5667967	2.67311425	8.07404E-10	145.75861	293.9360072	367.852

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

STF-PIA-10-9 Attachment

Appendix D

Compliance Assurance Monitoring (CAM) Forms

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GEORGIA ENVIRONMENTAL PROTECTION DIVISION
AIR PROTECTION BRANCH
4244 INTERNATIONAL PARKWAY, SUITE 120
ATLANTA, GEORGIA 30354

FOR APPLICANT'S USE

Revision #: _____
Date: / __ /
Page _____ of _____
Source Designation:
_____

COMPLIANCE ASSURANCE MONITORING (CAM) PLAN

FOR AGENCY USE ONLY
AIRS NUMBER:
PERMIT #:
APPLICATION NUMBER:

FOR INFORMATION ABOUT THE CAM RULE AND THIS FORM, PLEASE REFER TO 40 CFR PART 64. ADDITIONAL INFORMATION (INCLUDING GUIDANCE DOCUMENTS) MAY ALSO BE FOUND AT http://www.epa.gov/ttn/emc/cam.html

SOURCE INFORMATION

1) SOURCE NAME:
Yates Steam-Electric Generating Plant

2) DATE FORM	3) AIRS NUMBER:
December 2023	04-13-077-0001

BASIS OF CAM SUBMITTAL

4) MARK THE APPROPRIATE BOX BELOW AS TO WHY THIS CAM PLAN IS BEING SUBMITTED AS PART OF AN APPLICATION FOR A TITLE V PERMIT:

☐ RENEWAL APPLICATION. **ALL** PSEUs (POLLUTANT-SPECIFIC EMISSIONS UNITS CONSIDERED SEPARATELY WITH RESPECT TO EACH REGULATED AIR POLLUTANT) FOR WHICH A CAM PLAN HAS NOT YET BEEN APPROVED NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL.

☐ INITIAL APPLICATION (SUBMITTED AFTER 4/20/98). **ONLY** LARGE PSEUs (PSEUs WITH POTENTIAL POST-CONTROL DEVICE EMISSIONS OF AN APPLICABLE REGULATED AIR POLLUTANT THAT ARE EQUAL TO OR GREATER THAN MAJOR SOURCE THRESHOLD LEVELS) NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL.

☒ SIGNIFICANT MODIFICATION TO LARGE PSEUs. **ONLY** LARGE PSEUs BEING MODIFIED AFTER 4/20/98 NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. FOR LARGE PSEUs WITH AN APPROVED CAM PLAN, ONLY ADDRESS THE APPROPRIATE MONITORING REQUIREMENTS AFFECTED BY THE SIGNIFICANT MODIFICATION.

CAM APPLICABILITY DETERMINATION

5) DOES THE SOURCE HAVE A PSEU THAT IS SUBJECT TO CAM, 40 CFR PART 64, WHICH MUST BE ADDRESSED IN THIS CAM PLAN SUBMITTAL? TO DETERMINE APPLICABILITY, A PSEU MUST MEET **ALL** OF THE FOLLOWING CRITERIA (IF NO, THEN THE REMAINDER OF THIS FORM NEED NOT BE COMPLETED): ☒ YES ☐ NO

a. THE PSEU IS LOCATED AT A MAJOR SOURCE THAT IS REQUIRED TO OBTAIN A TITLE V PERMIT;

b. THE PSEU IS SUBJECT TO AN EMISSION LIMITATION OR STANDARD FOR THE APPLICABLE REGULATED AIR POLLUTANT THAT IS NOT EXEMPT;

LIST OF EXEMPT EMISSION LIMITATIONS OR STANDARDS:

- NSPS (40 CFR PART 60) OR NESHAP (40 CFR PARTS 61 AND 63) PROPOSED AFTER 11/15/1990.
- STRATOSPHERIC OZONE PROTECTION REQUIREMENTS.
- ACID RAIN PROGRAM REQUIREMENTS.
- EMISSION LIMITATIONS OR STANDARDS FOR WHICH A GEORGIA AIR QUALITY PERMIT SPECIFIES A CONTINUOUS COMPLIANCE DETERMINATION METHOD, AS DEFINED IN 40 CFR 64.1.
- AN EMISSION CAP THAT MEETS THE REQUIREMENTS SPECIFIED IN 40 CFR 70.4(b)(12).

c. THE PSEU USES AN ADD-ON CONTROL DEVICE (AS DEFINED IN 40 CFR 64.1) TO ACHIEVE COMPLIANCE WITH AN EMISSION LIMITATION OR STANDARD;

d. THE PSEU HAS POTENTIAL PRE-CONTROL DEVICE EMISSIONS OF THE APPLICABLE REGULATED AIR POLLUTANT THAT ARE EQUAL TO OR GREATER THAN THE PART 70 MAJOR SOURCE THRESHOLD LEVELS; AND

e. THE PSEU IS NOT AN EXEMPT BACKUP UTILITY POWER EMISSIONS UNIT THAT IS MUNICIPALLY-OWNED.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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6) [a]BACKGROUND DATA AND INFORMATION

COMPLETE THE FOLLOWING TABLE FOR **ALL** PSEUs THAT NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION IS TO BE USED TO PROVIDE BACKGROUND DATA AND INFORMATION FOR EACH PSEU IN ORDER TO SUPPLEMENT THE SUBMITTAL REQUIREMENTS SPECIFIED IN 40 CFR 64.4. IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY.

PSEU DESIGNATION	DESCRIPTION	POLLUTANT	CONTROL DEVICE	[b]EMISSION LIMITATION OR STANDARD	[c]MONITORING REQUIREMENT
Unit 8 (CT8)	Combustion Turbine Unit 8	NOx	Selective Catalytic Reduction	2.5 ppmvd, corrected to 15% O2, 4-hour rolling average, excluding startup, shutdown, and fuel switching (gas) 5.0 ppmvd, corrected to 15% O2, 4-hour rolling average, excluding startup, shutdown, and fuel switching (distillate oil) 6.0 ppmvd, corrected to 15% O2, 30-operating day rolling average, excluding startup, shutdown, and fuel switching (ozone season only)	Continuous Emissions Monitoring System (CEMS)
Unit 9 (CT8)	Combustion Turbine Unit 9				
Unit 10 (CT10)	Combustion Turbine Unit 10				
EXAMPLE BOILER NO. 1	WOOD-FIRED BOILER	PM	MULTICLONE	391-3-1-.02(2)(d)2.(ii); $0.5(10/R)^{0.5}$ lb/mmBtu	MONITOR PRESSURE DROP ACROSS MULTICLONE WEEKLY INSPECTION OF MULTICLONE

[a]IF A CONTROL DEVICE IS COMMON TO MORE THAN ONE PSEU, ONE MONITORING PLAN MAY BE SUBMITTED FOR THE CONTROL DEVICE WITH THE AFFECTED PSEUS IDENTIFIED AND ANY CONDITIONS THAT MUST BE MAINTAINED OR MONITORED IN ACCORDANCE WITH 64.3(a). IF A SINGE PSEU IS CONTROLLED BY MORE THAN ONE CONTROL DEVICE SIMILAR IN DESIGN AND OPERATION, ONE MONITORING PLAN FOR THE APPLICABLE CONTROL DEVICES MAY BE SUBMITTED WITH THE APPLICABLE CONTROL DEVICES IDENTIFIED AND ANY CONDITIONS THAT MUST BE MAINTAINED OR MONITORED IN ACCORDANCE WITH 64.3(a).

[b]INDICATE THE EMISSION LIMITATION OR STANDARD FOR ANY APPLICABLE REQUIREMENT THAT CONSTITUTES AN EMISSION LIMITATION, EMISSION STANDARD, OR STANDARD OF PERFORMANCE (AS DEFINED IN 40 CFR 64.1).

[c]INDICATE THE MONITORING REQUIREMENTS FOR THE PSEU THAT ARE REQUIRED BY AN APPLICABLE REGULATION OR PERMIT CONDITION.

APPLICATION PAGE _____

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CAM MONITORING APPROACH CRITERIA

COMPLETE THIS SECTION FOR **EACH** PSEU THAT NEEDS TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION MAY BE COPIED AS NEEDED FOR EACH PSEU. THIS SECTION IS TO BE USED TO PROVIDE MONITORING DATA AND INFORMATION FOR EACH INDICATOR SELECTED FOR EACH PSEU IN ORDER TO MEET THE MONITORING DESIGN CRITERIA SPECIFIED IN 40 CFR 64.3 AND 64.4. IF MORE THAN TWO INDICATORS ARE BEING SELECTED FOR A PSEU OR IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION, POLLUTANT, AND INDICATOR NOs.

7a) PSEU DESIGNATION:	**7b) POLLUTANT:**	**7c) [a]INDICATOR NO. 1:**	**7d) [a]INDICATOR NO. 2:**
CT9, CT9, CT10	**NOx**	**CEMS NOx Value**	
8a) GENERAL CRITERIA DESCRIBE THE MONITORING APPROACH USED TO MEASURE THE INDICATORS:		NOx and O2 are monitored continuously by CEMS. The unit control system adjusts ammonia injection as needed to maintain compliance.	
[b]ESTABLISH THE APPROPRIATE INDICATOR RANGE OR THE PROCEDURES FOR ESTABLISHING THE INDICATOR RANGE WHICH PROVIDES A REASONABLE ASSURANCE OF COMPLIANCE:		2.5 ppmvd 4-hour rolling avg. (gas) 5.0 ppmvd 4-hour rolling avg. (oil) 6.0 ppmvd 30-day rolling avg. (ozone season)	
8b) PERFORMANCE CRITERIA PROVIDE THE SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, SUCH AS DETECTOR LOCATION, INSTALLATION SPECIFICATIONS, AND MINIMUM ACCEPTABLE ACCURACY:		NOx and O2 are monitored with a CEMS that is certified under 40 CFR Part 75.	
[c]FOR NEW OR MODIFIED MONITORING EQUIPMENT, PROVIDE VERIFICATION PROCEDURES, INCLUDING MANUFACTURER'S RECOMMENDATIONS, TO CONFIRM THE OPERATIONAL STATUS OF THE MONITORING:			
PROVIDE QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES THAT ARE ADEQUATE TO ENSURE THE CONTINUING VALIDITY OF THE DATA, (i.e., DAILY CALIBRATIONS, VISUAL INSPECTIONS, ROUTINE MAINTENANCE, CGA, RATA, ETC.):		NOx and O2 analyzers are calibrated daily and maintained according to the QA/QC program developed specifically for the plant.	
[d]PROVIDE THE MONITORING FREQUENCY:		NOx and O2 are monitored continuously except during calibration and maintenance.	
PROVIDE THE DATA COLLECTION PROCEDURES THAT WILL BE USED:		The DAS retains all hourly average NOx and O2 measurements.	
PROVIDE THE DATA AVERAGING PERIOD FOR THE PURPOSE OF DETERMINING WHETHER AN EXCURSION OR EXCEEDANCE HAS OCCURRED:		Hourly averages based on at least 30 minutes operating time using 1-minute data.	

[a]DESCRIBE ALL INDICATORS TO BE MONITORED WHICH SATISFIES 40 CFR 64.3(a). INDICATORS OF EMISSION CONTROL PERFORMANCE FOR THE CONTROL DEVICE AND ASSOCIATED CAPTURE SYSTEM MAY INCLUDE MEASURED OR PREDICTED EMISSIONS (INCLUDING VISIBLE EMISSIONS OR OPACITY), PROCESS AND CONTROL DEVICE OPERATING PARAMETERS THAT AFFECT CONTROL DEVICE (AND CAPTURE SYSTEM) EFFICIENCY OR EMISSION RATES, OR RECORDED FINDINGS OF INSPECTION AND MAINTENANCE ACTIVITIES.

[b]INDICATOR RANGES MAY BE BASED ON A SINGLE MAXIMUM OR MINIMUM VALUE OR AT MULTIPLE LEVELS THAT ARE RELEVANT TO DISTINCTLY DIFFERENT OPERATING CONDITIONS, EXPRESSED AS A FUNCTION OF PROCESS VARIABLES, EXPRESSED AS MAINTAINING THE APPLICABLE INDICATOR IN A PARTICULAR OPERATIONAL STATUS OR DESIGNATED CONDITION, OR ESTABLISHED AS INTERDEPENDENT BETWEEN MORE THAN ONE INDICATOR. FOR CEMS, COMS, OR PEMS, INCLUDE THE MOST RECENT CERTIFICATION TEST FOR THE MONTIOR.

[c]THE VERIFICATION FOR OPERATIONAL STATUS SHOULD INCLUDE PROCEDURES FOR INSTALLATION, CALIBRATION, AND OPERATION OF THE MONITORING EQUIPMENT, CONDUCTED IN ACCORDANCE WITH THE MANUFACTURER'S RECOMMENDATIONS, NECESSARY TO CONFIRM THE MONITORING EQUIPMENT IS OPERATIONAL PRIOR TO THE COMMENCEMENT OF THE REQUIRED MONITORING.

[d]EMISSION UNITS WITH POSTCONTROL PTE ≥ 100 PERCENT OF THE AMOUNT CLASSIFYING THE SOURCE AS A MAJOR SOURCE MUST COLLECT FOUR OR MORE VALUES PER HOUR TO BE AVERAGED. A REDUCED DATA COLLECTION FREQUENCY MAY BE APPROVED IN LIMITED CIRCUMSTANCES. OTHER EMISSION UNITS MUST COLLECT DATA AT LEAST ONCE PER 24 HOUR PERIOD.

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RATIONALE AND JUSTIFICATION

COMPLETE THIS SECTION FOR **EACH** PSEU THAT NEEDS TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION MAY BE COPIED AS NEEDED FOR EACH PSEU. THIS SECTION IS TO BE USED TO PROVIDE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF EACH INDICATOR AND MONITORING APPROACH AND EACH INDICATOR RANGE IN ORDER TO MEET THE SUBMITTAL REQUIREMENTS SPECIFIED IN 40 CFR 64.4.

9a) PSEU DESIGNATION:	9b) REGULATED AIR POLLUTANT:
CT9, CT9, CT10	**NOx**

10) INDICATORS AND THE MONITORING APPROACH: PROVIDE THE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF THE INDICATORS AND THE MONITORING APPROACH USED TO MEASURE THE INDICATORS. ALSO PROVIDE ANY DATA SUPPORTING THE RATIONALE AND JUSTIFICATION. EXPLAIN THE REASONS FOR ANY DIFFERENCES BETWEEN THE VERIFICATION OF OPERATIONAL STATUS OR THE QUALITY ASSURANCE AND CONTROL PRACTICES PROPOSED AND THE MANUFACTURER'S RECOMMENDATIONS. (IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION AND POLLUTANT):

NOx concentration was selected as the CAM performance indicator. A properly calibrated and operated NOx CEMS provides accurate NOx emissions data. The NOx CEMS will be certified according to 40 CFR Part 75. The analyzers will be calibrated daily and maintained according to the QA/QC plan developed specifically for the plant.

11) INDICATOR RANGES: PROVIDE THE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF THE INDICATOR RANGES. THE RATIONALE AND JUSTIFICATION SHALL INDICATE HOW **EACH** INDICATOR RANGE WAS SELECTED BY EITHER A COMPLIANCE OR PERFORMANCE TEST, A TEST PLAN AND SCHEDULE, OR BY ENGINEERING ASSESSMENTS. DEPENDING ON WHICH METHOD IS BEING USED FOR EACH INDICATOR RANGE, INCLUDE THE SPECIFIC INFORMATION REQUIRED BELOW FOR THAT SPECIFIC INDICATOR RANGE. (IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION AND POLLUTANT):

- COMPLIANCE OR PERFORMANCE TEST (INDICATOR RANGES DETERMINED FROM CONTROL DEVICE OPERATING PARAMETER DATA OBTAINED DURING A COMPLIANCE OR PERFORMANCE TEST CONDUCTED UNDER REGULATORY SPECIFIED CONDITIONS OR UNDER CONDITIONS REPRESENTATIVE OF MAXIMUM POTENTIAL EMISSIONS UNDER ANTICIPATED OPERATING CONDITIONS. SUCH DATA MAY BE SUPPLEMENTED BY ENGINEERING ASSESSMENTS AND MANUFACTURER'S RECOMMENDATIONS). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE A SUMMARY OF THE COMPLIANCE OR PERFORMANCE TEST RESULTS THAT WAS USED TO DETERMINE THE INDICATOR RANGE AND DOCUMENTATION INDICATING THAT NO CHANGES HAVE TAKEN PLACE THAT COULD RESULT IN A SIGNIFICANT CHANGE IN THE CONTROL SYSTEM PERFORMANCE OR THE SELECTED INDICATOR RANGES SINCE THE COMPLIANCE OR PERFORMANCE TEST WAS CONDUCTED.
- TEST PLAN AND SCHEDULE (INDICATOR RANGES WILL BE DETERMINED FROM A PROPOSED IMPLEMENTATION PLAN AND SCHEDULE FOR INSTALLING, TESTING, AND PERFORMING ANY OTHER APPROPRIATE ACTIVITIES PRIOR TO USE OF THE MONITORING). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE THE PROPOSED IMPLEMENTATION PLAN AND SCHEDULE THAT WILL PROVIDE FOR USE OF THE MONITORING AS EXPEDITIOUSLY AS PRACTICABLE AFTER APPROVAL OF THIS CAM PLAN, BUT IN NO CASE SHALL THE SCHEDULE FOR COMPLETING INSTALLATION AND BEGINNING OPERATION OF THE MONITORING EXCEED 180 DAYS AFTER APPROVAL.
- ENGINEERING ASSESSMENTS (INDICATOR RANGES OR THE PROCEDURES FOR ESTABLISHING INDICATOR RANGES ARE DETERMINED FROM ENGINEERING ASSESSMENTS AND OTHER DATA, SUCH AS MANUFACTURERS' DESIGN CRITERIA AND HISTORICAL MONITORING DATA, BECAUSE FACTORS SPECIFIC TO THE TYPE OF MONITORING, CONTROL DEVICE, OR PSEU MAKE COMPLIANCE OR PERFORMANCE TESTING UNNECESSARY). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE DOCUMENTATION DEMONSTRATING THAT COMPLIANCE TESTING IS NOT REQUIRED TO ESTABLISH THE INDICATOR RANGE.

RATIONALE AND JUSTIFICATION:

NOx CEMS is a direct measurement of the NOx concentration. If the NOx concentration approaches the emissions limit, corrective action will be taken to ensure the limit is not exceeded. If the 4-hour rolling NOx average is above the emissions limit, an exceedance has occurred. If the 30-day rolling NOx average is above the emissions limit, excess emissions have occurred.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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GEORGIA ENVIRONMENTAL PROTECTION DIVISION
AIR PROTECTION BRANCH
4244 INTERNATIONAL PARKWAY, SUITE 120
ATLANTA, GEORGIA 30354

FOR APPLICANT'S USE
Revision #: _____
Date: / __ /
Page _____ of _____
Source Designation:
_____

COMPLIANCE ASSURANCE MONITORING (CAM) PLAN	***FOR AGENCY USE ONLY***
	AIRS NUMBER:
	PERMIT #:
	APPLICATION NUMBER:

FOR INFORMATION ABOUT THE CAM RULE AND THIS FORM, PLEASE REFER TO 40 CFR PART 64. ADDITIONAL INFORMATION (INCLUDING GUIDANCE DOCUMENTS) MAY ALSO BE FOUND AT http://www.epa.gov/ttn/emc/cam.html

SOURCE INFORMATION

1) SOURCE NAME:
Yates Steam-Electric Generating Plant

2) DATE FORM	3) AIRS NUMBER:
December 2023	04-13-077-0001

BASIS OF CAM SUBMITTAL

4) MARK THE APPROPRIATE BOX BELOW AS TO WHY THIS CAM PLAN IS BEING SUBMITTED AS PART OF AN APPLICATION FOR A TITLE V PERMIT:

☐ RENEWAL APPLICATION. **ALL** PSEUs (POLLUTANT-SPECIFIC EMISSIONS UNITS CONSIDERED SEPARATELY WITH RESPECT TO EACH REGULATED AIR POLLUTANT) FOR WHICH A CAM PLAN HAS NOT YET BEEN APPROVED NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL.

☐ INITIAL APPLICATION (SUBMITTED AFTER 4/20/98). **ONLY** LARGE PSEUs (PSEUs WITH POTENTIAL POST-CONTROL DEVICE EMISSIONS OF AN APPLICABLE REGULATED AIR POLLUTANT THAT ARE EQUAL TO OR GREATER THAN MAJOR SOURCE THRESHOLD LEVELS) NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL.

☒ SIGNIFICANT MODIFICATION TO LARGE PSEUs. **ONLY** LARGE PSEUs BEING MODIFIED AFTER 4/20/98 NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. FOR LARGE PSEUs WITH AN APPROVED CAM PLAN, ONLY ADDRESS THE APPROPRIATE MONITORING REQUIREMENTS AFFECTED BY THE SIGNIFICANT MODIFICATION.

CAM APPLICABILITY DETERMINATION

5) DOES THE SOURCE HAVE A PSEU THAT IS SUBJECT TO CAM, 40 CFR PART 64, WHICH MUST BE ADDRESSED IN THIS CAM PLAN SUBMITTAL? TO DETERMINE APPLICABILITY, A PSEU MUST MEET **ALL** OF THE FOLLOWING CRITERIA (IF NO, THEN THE REMAINDER OF THIS FORM NEED NOT BE COMPLETED): ☒ YES ☐ NO

a. THE PSEU IS LOCATED AT A MAJOR SOURCE THAT IS REQUIRED TO OBTAIN A TITLE V PERMIT;

b. THE PSEU IS SUBJECT TO AN EMISSION LIMITATION OR STANDARD FOR THE APPLICABLE REGULATED AIR POLLUTANT THAT IS NOT EXEMPT;

LIST OF EXEMPT EMISSION LIMITATIONS OR STANDARDS:

- NSPS (40 CFR PART 60) OR NESHAP (40 CFR PARTS 61 AND 63) PROPOSED AFTER 11/15/1990.
- STRATOSPHERIC OZONE PROTECTION REQUIREMENTS.
- ACID RAIN PROGRAM REQUIREMENTS.
- EMISSION LIMITATIONS OR STANDARDS FOR WHICH A GEORGIA AIR QUALITY PERMIT SPECIFIES A CONTINUOUS COMPLIANCE DETERMINATION METHOD, AS DEFINED IN 40 CFR 64.1.
- AN EMISSION CAP THAT MEETS THE REQUIREMENTS SPECIFIED IN 40 CFR 70.4(b)(12).

c. THE PSEU USES AN ADD-ON CONTROL DEVICE (AS DEFINED IN 40 CFR 64.1) TO ACHIEVE COMPLIANCE WITH AN EMISSION LIMITATION OR STANDARD;

d. THE PSEU HAS POTENTIAL PRE-CONTROL DEVICE EMISSIONS OF THE APPLICABLE REGULATED AIR POLLUTANT THAT ARE EQUAL TO OR GREATER THAN THE PART 70 MAJOR SOURCE THRESHOLD LEVELS; AND

e. THE PSEU IS NOT AN EXEMPT BACKUP UTILITY POWER EMISSIONS UNIT THAT IS MUNICIPALLY-OWNED.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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6) [a]BACKGROUND DATA AND INFORMATION

COMPLETE THE FOLLOWING TABLE FOR **ALL** PSEUs THAT NEED TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION IS TO BE USED TO PROVIDE BACKGROUND DATA AND INFORMATION FOR EACH PSEU IN ORDER TO SUPPLEMENT THE SUBMITTAL REQUIREMENTS SPECIFIED IN 40 CFR 64.4. IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY.

PSEU DESIGNATION	DESCRIPTION	POLLUTANT	CONTROL DEVICE	[b]EMISSION LIMITATION OR STANDARD	[c]MONITORING REQUIREMENT
Unit 8 (CT8)	Combustion Turbine Unit 8	CO and VOC	Oxidation Catalyst	3.5 ppmvd CO and 2.0 ppmvd VOC, corrected to 15% O2, 4-hour rolling average, excluding startup, shutdown, and fuel switching (gas) 5.0 ppmvd CO and 2 ppm VOC, corrected to 15% O2, 4-hour rolling average, excluding startup, shutdown, and fuel switching (distillate oil)	Continuous Emissions Monitoring System (CEMS)
Unit 9 (CT8)	Combustion Turbine Unit 9				
Unit 10 (CT10)	Combustion Turbine Unit 10				
EXAMPLE BOILER NO. 1	WOOD-FIRED BOILER	PM	MULTICLONE	391-3-1-.02(2)(d)2.(ii); $0.5(10/R)^{0.5}$ lb/mmBtu	MONITOR PRESSURE DROP ACROSS MULTICLONE WEEKLY INSPECTION OF MULTICLONE

[a]IF A CONTROL DEVICE IS COMMON TO MORE THAN ONE PSEU, ONE MONITORING PLAN MAY BE SUBMITTED FOR THE CONTROL DEVICE WITH THE AFFECTED PSEUS IDENTIFIED AND ANY CONDITIONS THAT MUST BE MAINTAINED OR MONITORED IN ACCORDANCE WITH 64.3(a). IF A SINGE PSEU IS CONTROLLED BY MORE THAN ONE CONTROL DEVICE SIMILAR IN DESIGN AND OPERATION, ONE MONITORING PLAN FOR THE APPLICABLE CONTROL DEVICES MAY BE SUBMITTED WITH THE APPLICABLE CONTROL DEVICES IDENTIFIED AND ANY CONDITIONS THAT MUST BE MAINTAINED OR MONITORED IN ACCORDANCE WITH 64.3(a).

[b]INDICATE THE EMISSION LIMITATION OR STANDARD FOR ANY APPLICABLE REQUIREMENT THAT CONSTITUTES AN EMISSION LIMITATION, EMISSION STANDARD, OR STANDARD OF PERFORMANCE (AS DEFINED IN 40 CFR 64.1).

[c]INDICATE THE MONITORING REQUIREMENTS FOR THE PSEU THAT ARE REQUIRED BY AN APPLICABLE REGULATION OR PERMIT CONDITION.

APPLICATION PAGE _____

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CAM MONITORING APPROACH CRITERIA

COMPLETE THIS SECTION FOR **EACH** PSEU THAT NEEDS TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION MAY BE COPIED AS NEEDED FOR EACH PSEU. THIS SECTION IS TO BE USED TO PROVIDE MONITORING DATA AND INFORMATION FOR EACH INDICATOR SELECTED FOR EACH PSEU IN ORDER TO MEET THE MONITORING DESIGN CRITERIA SPECIFIED IN 40 CFR 64.3 AND 64.4. IF MORE THAN TWO INDICATORS ARE BEING SELECTED FOR A PSEU OR IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION, POLLUTANT, AND INDICATOR NOs.

7a) PSEU DESIGNATION:	**7b) POLLUTANT:**	**7c) [a]INDICATOR NO. 1:**	**7d) [a]INDICATOR NO. 2:**
CT9, CT9, CT10	**CO and VOC**	**CEMS CO Value**	
8a) GENERAL CRITERIA DESCRIBE THE MONITORING APPROACH USED TO MEASURE THE INDICATORS:		CO and O2 are monitored continuously by CEMS.	
[b]ESTABLISH THE APPROPRIATE INDICATOR RANGE OR THE PROCEDURES FOR ESTABLISHING THE INDICATOR RANGE WHICH PROVIDES A REASONABLE ASSURANCE OF COMPLIANCE:		3.5 ppmvd 4-hour rolling avg. (gas) 5.0 ppmvd 4-hour rolling avg. (oil)	
8b) PERFORMANCE CRITERIA PROVIDE THE SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, SUCH AS DETECTOR LOCATION, INSTALLATION SPECIFICATIONS, AND MINIMUM ACCEPTABLE ACCURACY:		CO is monitored with CEMS certified under 40 CFR Part 60, PS-4A and O2 is monitored with CEMS certified under 40 CFR Part 75.	
[c]FOR NEW OR MODIFIED MONITORING EQUIPMENT, PROVIDE VERIFICATION PROCEDURES, INCLUDING MANUFACTURER'S RECOMMENDATIONS, TO CONFIRM THE OPERATIONAL STATUS OF THE MONITORING:			
PROVIDE QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES THAT ARE ADEQUATE TO ENSURE THE CONTINUING VALIDITY OF THE DATA, (i.e., DAILY CALIBRATIONS, VISUAL INSPECTIONS, ROUTINE MAINTENANCE, CGA, RATA, ETC.):		CO and O2 analyzers are calibrated daily and maintained according to the QA/QC program developed specifically for the plant.	
[d]PROVIDE THE MONITORING FREQUENCY:		CO and O2 are monitored continuously except during calibration and maintenance.	
PROVIDE THE DATA COLLECTION PROCEDURES THAT WILL BE USED:		The DAS retains all hourly average CO and O2 measurements.	
PROVIDE THE DATA AVERAGING PERIOD FOR THE PURPOSE OF DETERMINING WHETHER AN EXCURSION OR EXCEEDANCE HAS OCCURRED:		Hourly averages based on at least 30 minutes operating time using 1-minute data.	

[a]DESCRIBE ALL INDICATORS TO BE MONITORED WHICH SATISFIES 40 CFR 64.3(a). INDICATORS OF EMISSION CONTROL PERFORMANCE FOR THE CONTROL DEVICE AND ASSOCIATED CAPTURE SYSTEM MAY INCLUDE MEASURED OR PREDICTED EMISSIONS (INCLUDING VISIBLE EMISSIONS OR OPACITY), PROCESS AND CONTROL DEVICE OPERATING PARAMETERS THAT AFFECT CONTROL DEVICE (AND CAPTURE SYSTEM) EFFICIENCY OR EMISSION RATES, OR RECORDED FINDINGS OF INSPECTION AND MAINTENANCE ACTIVITIES.

[b]INDICATOR RANGES MAY BE BASED ON A SINGLE MAXIMUM OR MINIMUM VALUE OR AT MULTIPLE LEVELS THAT ARE RELEVANT TO DISTINCTLY DIFFERENT OPERATING CONDITIONS, EXPRESSED AS A FUNCTION OF PROCESS VARIABLES, EXPRESSED AS MAINTAINING THE APPLICABLE INDICATOR IN A PARTICULAR OPERATIONAL STATUS OR DESIGNATED CONDITION, OR ESTABLISHED AS INTERDEPENDENT BETWEEN MORE THAN ONE INDICATOR. FOR CEMS, COMS, OR PEMS, INCLUDE THE MOST RECENT CERTIFICATION TEST FOR THE MONTIOR.

[c]THE VERIFICATION FOR OPERATIONAL STATUS SHOULD INCLUDE PROCEDURES FOR INSTALLATION, CALIBRATION, AND OPERATION OF THE MONITORING EQUIPMENT, CONDUCTED IN ACCORDANCE WITH THE MANUFACTURER'S RECOMMENDATIONS, NECESSARY TO CONFIRM THE MONITORING EQUIPMENT IS OPERATIONAL PRIOR TO THE COMMENCEMENT OF THE REQUIRED MONITORING.

[d]EMISSION UNITS WITH POSTCONTROL PTE ≥ 100 PERCENT OF THE AMOUNT CLASSIFYING THE SOURCE AS A MAJOR SOURCE MUST COLLECT FOUR OR MORE VALUES PER HOUR TO BE AVERAGED. A REDUCED DATA COLLECTION FREQUENCY MAY BE APPROVED IN LIMITED CIRCUMSTANCES. OTHER EMISSION UNITS MUST COLLECT DATA AT LEAST ONCE PER 24 HOUR PERIOD.

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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RATIONALE AND JUSTIFICATION

COMPLETE THIS SECTION FOR **EACH** PSEU THAT NEEDS TO BE ADDRESSED IN THIS CAM PLAN SUBMITTAL. THIS SECTION MAY BE COPIED AS NEEDED FOR EACH PSEU. THIS SECTION IS TO BE USED TO PROVIDE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF EACH INDICATOR AND MONITORING APPROACH AND EACH INDICATOR RANGE IN ORDER TO MEET THE SUBMITTAL REQUIREMENTS SPECIFIED IN 40 CFR 64.4.

9a) PSEU DESIGNATION:	9b) REGULATED AIR POLLUTANT:
CT9, CT9, CT10	**CO and VOC**

10) INDICATORS AND THE MONITORING APPROACH: PROVIDE THE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF THE INDICATORS AND THE MONITORING APPROACH USED TO MEASURE THE INDICATORS. ALSO PROVIDE ANY DATA SUPPORTING THE RATIONALE AND JUSTIFICATION. EXPLAIN THE REASONS FOR ANY DIFFERENCES BETWEEN THE VERIFICATION OF OPERATIONAL STATUS OR THE QUALITY ASSURANCE AND CONTROL PRACTICES PROPOSED AND THE MANUFACTURER'S RECOMMENDATIONS. (IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION AND POLLUTANT):

CO and VOC are controlled by the same pollution control equipment. CO concentration was selected as the CAM performance indicator because CO can be monitored continuously and provides an indiacator of catalyst performance. A properly calibrated and operated CO CEMS provides accurate CO emissions data and is an indicator of VOC emissions performance. The CO CEMS will be certified according to 40 CFR Part 60, PS-4A. The analyzers are calibrated daily and maintained according to the QA/QC plan developed specifically for the plant.

11) INDICATOR RANGES: PROVIDE THE RATIONALE AND JUSTIFICATION FOR THE SELECTION OF THE INDICATOR RANGES. THE RATIONALE AND JUSTIFICATION SHALL INDICATE HOW **EACH** INDICATOR RANGE WAS SELECTED BY EITHER A COMPLIANCE OR PERFORMANCE TEST, A TEST PLAN AND SCHEDULE, OR BY ENGINEERING ASSESSMENTS. DEPENDING ON WHICH METHOD IS BEING USED FOR EACH INDICATOR RANGE, INCLUDE THE SPECIFIC INFORMATION REQUIRED BELOW FOR THAT SPECIFIC INDICATOR RANGE. (IF ADDITIONAL SPACE IS NEEDED, ATTACH AND LABEL ACCORDINGLY WITH THE APPROPRIATE PSEU DESIGNATION AND POLLUTANT):

- COMPLIANCE OR PERFORMANCE TEST (INDICATOR RANGES DETERMINED FROM CONTROL DEVICE OPERATING PARAMETER DATA OBTAINED DURING A COMPLIANCE OR PERFORMANCE TEST CONDUCTED UNDER REGULATORY SPECIFIED CONDITIONS OR UNDER CONDITIONS REPRESENTATIVE OF MAXIMUM POTENTIAL EMISSIONS UNDER ANTICIPATED OPERATING CONDITIONS. SUCH DATA MAY BE SUPPLEMENTED BY ENGINEERING ASSESSMENTS AND MANUFACTURER'S RECOMMENDATIONS). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE A SUMMARY OF THE COMPLIANCE OR PERFORMANCE TEST RESULTS THAT WAS USED TO DETERMINE THE INDICATOR RANGE AND DOCUMENTATION INDICATING THAT NO CHANGES HAVE TAKEN PLACE THAT COULD RESULT IN A SIGNIFICANT CHANGE IN THE CONTROL SYSTEM PERFORMANCE OR THE SELECTED INDICATOR RANGES SINCE THE COMPLIANCE OR PERFORMANCE TEST WAS CONDUCTED.
- TEST PLAN AND SCHEDULE (INDICATOR RANGES WILL BE DETERMINED FROM A PROPOSED IMPLEMENTATION PLAN AND SCHEDULE FOR INSTALLING, TESTING, AND PERFORMING ANY OTHER APPROPRIATE ACTIVITIES PRIOR TO USE OF THE MONITORING). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE THE PROPOSED IMPLEMENTATION PLAN AND SCHEDULE THAT WILL PROVIDE FOR USE OF THE MONITORING AS EXPEDITIOUSLY AS PRACTICABLE AFTER APPROVAL OF THIS CAM PLAN, BUT IN NO CASE SHALL THE SCHEDULE FOR COMPLETING INSTALLATION AND BEGINNING OPERATION OF THE MONITORING EXCEED 180 DAYS AFTER APPROVAL.
- ENGINEERING ASSESSMENTS (INDICATOR RANGES OR THE PROCEDURES FOR ESTABLISHING INDICATOR RANGES ARE DETERMINED FROM ENGINEERING ASSESSMENTS AND OTHER DATA, SUCH AS MANUFACTURERS' DESIGN CRITERIA AND HISTORICAL MONITORING DATA, BECAUSE FACTORS SPECIFIC TO THE TYPE OF MONITORING, CONTROL DEVICE, OR PSEU MAKE COMPLIANCE OR PERFORMANCE TESTING UNNECESSARY). THE RATIONALE AND JUSTIFICATION SHALL INCLUDE DOCUMENTATION DEMONSTRATING THAT COMPLIANCE TESTING IS NOT REQUIRED TO ESTABLISH THE INDICATOR RANGE.

RATIONALE AND JUSTIFICATION:

CO CEMS is a direct measurement of the CO concentration and an indicator of VOC concentration and catalyst performance. If the CO concentration approaches the emissions limit, corrective action will be taken to ensure the limit is not exceeded. If the 4-hour rolling CO average is above the emissions limit, an exceedance has occurred.

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STF-PIA-10-9 Attachment

Appendix E

Search Results from EPA's RACT/BACT/LAER Clearinghouse

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Table E-1
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR NOx

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Dry Low-NOx Combustion System (DLNB), Water Injection	9	PPMVD
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	25	PPMVD
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel	2.5	PPMVD
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	DLN	9	PPMVD
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	USE OF NATURAL GAS, WATER/STEAM INJECTION, AND A SELECTIVE CATAYTIC REDUCTION (SCR) SYSTEM	2.5	PPMVD
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Water injection plus SCR	5	PPMVD
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	water injection	25	PPMVD

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Table E-2
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2013 THROUGH 03/30/2023
LISTINGS FOR NOx

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW			
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	WATER INJECTION	42	ppmvd
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Low-NOx combustion technology and water injection	42	ppmvd
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	720	H/YR	SCR and water injection	5	ppmvd
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple Cycle Turbine	171	MW	DLN, WATER INJECTION, ULSD	42	ppmvd
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Wet injection	42	ppmvd
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MEGAWATT SIMPLE CYLCE COMBUSTION TURBINE, FIRING ULSD	120	MW	LIMITED USE OF ULSD, WATER/STEAM INJECTION, AND A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM.	5	ppmvd

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Table E-3
NATURAL GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TN	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	oxidation catalyst	5	PPMV
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		9	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	405.5	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	405.5	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices & use of pipeline quality natural gas	162.2	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	162.2	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	6	PPMV
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas	6	PPMV
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Combustion Controls	9	PPMV
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Dry low NOx burners	9	PPMV
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	858	PPMV
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Good Combustion Practices	9	PPMV
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	89.2	PPMV

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Table E-3
NATURAL GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0326	DOSWELL ENERGY CENTER	VA	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Pipeline Quality Natural Gas	3.2	PPMV
NY-0106	GREENIDGE STATION	NY	9/7/2016	Turbine - natural gas	107	MW		42.4	PPMV
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Add-on control is CO Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	5	PPMV
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	9	PPMV
TX-0777	UNION VALLEY ENERGY CENTER	TX	12/9/2015	Simple Cycle Turbine	183	MW	dry low NOx burners and good combustion practices	9	PPMV
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	TX	10/27/2015	Simple Cycle Turbine	183	MW	DLN burners and good combustion practices	9	PPMV
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	dry low NOx burners, good combustion practices, limited operation	9	PPMV
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	dry low NOx burners and lmiited operation, clean fuel	9	PPMV
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices; limited operating hours	9	PPMV
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	TX	5/8/2015	Simple Cycle Turbine	183	MW	DLN burners and good combustion practices	9	PPMV
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	(3) combustion turbines	220	MW	DLN combustors	4	PPMV
TX-0688	SR BERTRON ELECTRIC GENERATION STATION	TX	12/19/2014	Simple cycle natural gas turbines	225	MW	Good Combustion Practices	9	PPMV
CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	12/11/2014	Turbines - two simple cycle gas	799.7	MMBTU/H each	Catalytic Oxidation.	30.7	PPMV
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	DLN combustors	9	PPMV
TX-0695	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	(2) combustion turbines	180	MW	DLN combustors	9	PPMV
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	(6) simple cycle turbines	65	MW	DLN combustors	25	PPMV
TX-0686	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	Combustion Turbine-Generator(CTG)	202	MW	Good combustion practices; limited hours	9	PPMV
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	combustion turbine	202	MW	DLN combustors, good combustion practices	9	PPMV
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	Oxidation Catalyst	6	PPMV
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H	Catalytic oxidation system	6	PPMV

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Table E-3
NATURAL GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0701	ECTOR COUNTY ENERGY CENTER	TX	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Good combustion practices	6	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	utilize efficient combustion/design technology	70.2	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	utilize efficient combustion/design technology	9.8	PPMV
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combustion Turbine	986	MMBTU/H	Good Combustion	25	PPMV

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Table E-4
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2013 THROUGH 03/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Good Combustion Practices	20	PPMV
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	126.9	PPMV
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	720	H/YR	Oxidation Catalyst	5	PPMV
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple Cycle Turbine	171	MW	combustor designed for complete combustion and therefore minimizes emissions	20	PPMV

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Table E-3
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR VOC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of pipeline quality natural gas		
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Good combustion practices	2	PPMVD
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES		
CA-1238	PUENTE POWER	CA	10/13/2016	Gas turbine	262	MW		2	PPMV
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	2143980	MMBTU/YR	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2	PPMV
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMV

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Table E-3
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR VOC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Good combustion practices	2	PPMV
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW	good combustion	1.4	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE LM6000PC SPRINT Simple cycle combustion turbine	405.3	MMBTU/hr	utilize efficient combustion/design technology	11.2	PPMV
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	GE 7FA Simple Cycle Combustion Turbine	1780	MMBTU/HR	will utilize efficient combustion/design technology	1.4	PPMV

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Table E-6

NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2015 THROUGH 03/30/2023

LISTINGS FOR VOC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	720	H/YR	Oxidation catalyst	4.5	PPMVD@15% O2
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple Cycle Turbine	171	MW	combustor designed for complete combustion and therefore minimizes emissions	4.2	PPMVD as methane @15%O2

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Table E-3
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR TCM

	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
	EE VALLEY	TN	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	good combustion design and operating practices and the use of low sulfur fuel	0.008	lb/MMBtu
			/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
				ple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
					2262.4	MMBtu/hr gas	Use of clean fuels, and annual VE test		
					202	MW	Pipeline quality natural gas; limited hours; good combustion practices.		
							fire only pipeline quality natural gas	0.015	lb/MMBtu
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS					uality natural gas	0.010	lb/MMBtu

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Table E-8
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTING SORTED BY RBLC ID

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		0.008	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Use of pipeline quality natural gas and good combustion practices.		
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
TX-0826	MUSTANG STATION	TX	8/16/2017	Simple Cycle Turbine	162.8	MW	Pipeline quality natural gas and good combustion practices		
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	turbine design and good combustion practices	0.005	lb/MMBtu
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	643	MMBTU/hr	Use of Natural gas a clean burning fuel	0.008	lb/MMBtu
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	0.010	lb/MMBtu
TX-0777	UNION VALLEY ENERGY CENTER	TX	12/9/2015	Simple Cycle Turbine	183	MW	pipeline quality natural gas, good combustion practices	0.005	lb/MMBtu

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Table E-8
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTING FOR RBLC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	TX	10/27/2015	Simple Cycle Turbine	183	MW	Pipeline Quality Natural Gas	0.005	lb/MMBtu
	NACOGDOCHES POWER TRIC GENERATING	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
	Y	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.043	lb/MMBtu
			9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of clean fuels		
			15	Simple Cycle Turbine & Generator	202	MW	Pipeline quality natural gas; limited hours; good combustion practices.		
				SIMPLE CYCLE COMBUSTION NATURAL GAS	120	MW	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS	0.008	lb/MMBtu
					375	MMBTU/H	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	0.013	lb/MMBtu
							fire only pipeline quality natural gas	0.015	lb/MMBtu
							ipeline quality natural gas	0.010	lb/MMBtu
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combu				0.007	lb/MMBtu

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Table E-9
NATURAL-GAS-FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		0.008	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	0.003	lb/MMBtu
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Inlet air filtration.	0.010	lb/MMBtu
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines	920	MW	Use of pipeline quality natural gas and good combustion practices.		
TX-0833	JACKSON COUNTY GENERATORS	TX	1/26/2018	Combustion Turbines MSS	0		Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.		
TX-0826	MUSTANG STATION	TX	8/16/2017	Simple Cycle Turbine	162.8	MW	Pipeline quality natural gas and good combustion practices		
IN-0261	VERMILLION GENERATING STATION	IN	2/28/2017	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	80	MW	GOOD COMBUSTION PRACTICES	0.007	lb/MMBtu
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Inlet Air Filtration, Use of Natural Gas, Ultra-Low Sulfur Diesel	0.010	lb/MMBtu
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.007	lb/MMBtu
VA-0326	DOSWELL ENERGY CENTER	VA	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	0.006	lb/MMBtu

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Table E-9
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR TPM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	turbine design and good combustion practices		
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Natural gas	643	MMBTU/HR	Use of natural gas a clean burning fuel	0.008	lb/MMBtu
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	0.010	lb/MMBtu
TX-0777	UNION VALLEY ENERGY CENTER	TX	12/9/2015	Simple Cycle Turbine	183	MW	pipeline quality natural gas, good combustion practices	0.009	lb/MMBtu
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	TX	10/27/2015	Simple Cycle Turbine	183	MW	Pipeline Quality Natural Gas	0.005	lb/MMBtu
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	TX	10/14/2015	Natural Gas Simple Cycle Turbine (>25 MW)	232	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.006	lb/MMBtu
TX-0768	SHAWNEE ENERGY CENTER	TX	10/9/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0.043	lb/MMBtu
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of clean fuels		
TX-0733	ANTELOPE ELK ENERGY CENTER	TX	5/12/2015	Simple Cycle Turbine & Generator	202	MW	Pipeline quality natural gas; limited hours; good combustion practices.		
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	(3) combustion turbines	220	MW			
TX-0696	ROAN'S PRAIRIE GENERATING STATION	TX	9/22/2014	(2) simple cycle turbines	600	MW			
TX-0695	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	(2) combustion turbines	180	MW			
CO-0075	PUEBLO AIRPORT GENERATING STATION	CO	5/30/2014	Turbine - simple cycle gas	375	MMBTU/H	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	0.013	lb/MMBtu
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	(6) simple cycle turbines	65	MW			
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	combustion turbine	202	MW			
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H		0.012	lb/MMBtu
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H		0.012	lb/MMBtu

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Table E-9
NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR TPM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
	CTOR COUNTY ENERGY	TX	5/13/2013	Simple Cycle Combustion Turbines	180	MW	Firing pipeline quality natural gas and good combustion practices		
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combu	986	MMBTU/H	Good combustion practices.	0.007	lb/MMBtu

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Table E-10
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2018 THROUGH 03/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

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Table E-11
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2010 THROUGH 03/30/2023
LISTINGS FOR TPM2.5

	E	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
			8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	533.5	MMBtu/hr oil	Use of ULSD a clean burning fuel	0.026	lb/MMBtu
				urbine	171	MW	combustor designed for complete combustion and therefore minimizes emissions, and ULSD	0.007	lb/MMBtu
						MBtu/hr gas	Use of clean fuels. 0.0015% Sulfur in ULSD		
MD-0043	PERRYMAN GENERATING STATION	MD		COMBUSTION TURBINE, FIRING ULSD			N PRACTICES AND MBTU HIGH HEAT VALUE (HHV)	0.025	lb/MMBtu

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Table E-12
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2015 THROUGH 03/30/2023
LISTINGS FOR TPM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Inlet Air Filtration, Use of Natural Gas, Ultra-Low Sulfur Diesel	0.025	lb/MMBtu
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.012	lb/MMBtu
NJ-0086	BAYONNNE ENERGY CENTER	NJ	8/26/2016	Simple Cycle Stationary Turbines firing Ultra Low Sulfur Distillate Oil	533.5	MMBtu/hr oil	Use of ULSD, a clean burning fuel	0.026	lb/MMBtu
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple Cycle Turbine	171	MW	combustor designed for complete combustion and therefore minimizes emissions, ULSD	0.007	lb/MMBtu
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of clean fuels, 0.0015% Sulfur in ULSD		

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Table E-13

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023

LISTING OF RBLC ID'S FOR CO2E PM2.5 CO2

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TN-0187	TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TN	8/31/2022	Ten Simple Cycle NG Turbines	465.8	MMBtu/hr	Efficient turbine operation and good combustion practices	1140	LB/MWHR
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three 229 MW Simple Cycle Combustion Turbines	229	MW		1140	LB/MWHR
TX-0900	ECTOR COUNTY ENERGY CENTER	TX	8/17/2020	Simple Cycle Turbines	0		Best management practices and good combustion practices, clean fuel	1514	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	2201	MM BTU/hR	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
LA-0327	WASHINGTON PARISH ENERGY CENTER	LA	5/23/2018	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	2201	MM BTU/hr	Facility-wide energy efficiency measures, such as improved combustion measures, and use of pipeline quality natural gas.	1140	LB/MWHR
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Use of natural gas & use of GE 7FA.004	1300	LB/MWHR
TX-0826	MUSTANG STATION	TX	8/16/2017	Simple Cycle Turbine	162.8	MW	Pipeline quality natural gas and good combustion practices	1140	LB/MWHR
TX-0824	JACKSON COUNTY GENERATING FACILITY	TX	6/30/2017	Simple Cycle Turbines	920	MW	energy efficiency designs, practices, and procedures, CT inlet air cooling, periodic CT burner maintenance and tuning, reduction in heat loss, i.e., insulation of the CT, instrumentation and controls	1316	LB/MWHR
WV-0026	WAVERLY FACILITY	WV	1/23/2017	GE Model 7FA Turbine	1571	mmbtu/hr	Use of Natural Gas, Selection of GE7FA	1300	LB/MWHR
IN-0264	MONTPELIER GENERATING STATION	IN	1/6/2017	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	270.9	MMBTU/H	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	1121	LB/MWHR
VA-0326	DOSWELL ENERGY CENTER	VA	10/4/2016	Two (2) GE 7FA simple cycle combustion turbines	1961	MMBTU/HR	Good combustion, maintenance and use of active combustion dynamic monitoring systems.		

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Table E-13

NATURAL-GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25MW, PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023

LISTING OF RBLC ID'S FOR GHG PSD PERMITS

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Turbine-generator design and proper operation		
NY-0106	GREENIDGE STATION	NY	9/7/2016	Turbine - natural gas	107	MW		1236.615	LB/MWHR
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple cycle turbine	171	MW		1434	LB/MWHR
TX-0780	VAN ALSTYNE ENERGY CENTER	TX	1/13/2016	Simple Cycle Turbine	183	mw		1461	LB/MWHR
TX-0778	UNION VALLEY ENERGY CENTER	TX	12/16/2015	Simple Cycle Turbine	183	MW		1461	LB/MWHR
TX-0775	CLEAR SPRINGS ENERGY CENTER (CSEC)	TX	11/13/2015	Simple Cycle Turbine	183	MW	Low carbon fuel, good combustion, efficient combined cycle design	1461	LB/MWHR
TX-0771	SHAWNEE ENERGY CENTER	TX	11/10/2015	Simple cycle turbines greater than 25 megawatts (MW)	230	MW		1398	LB/MWHR
FL-0355	FORT MYERS PLANT	FL	9/10/2015	Combustion Turbines	2262.4	MMBtu/hr gas	Use of low-emitting fuel and efficient turbine	1374	LB/MWHR
TX-0735	ANTELOPE ELK ENERGY CENTER	TX	5/20/2015	Simple Cycle Turbine & Generator	202	MW	Energy efficiency, good design & combustion practices	1304	LB/MWHR
TX-0753	GUADALUPE GENERATING STATION	TX	12/2/2014	Simple Cycle Combustion Turbine Generator	10673	Btu/kWh		1293.3	LB/MWHR
TX-0758	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	Simple Cycle Combustion Turbine, GE 7FA.03	11707	Btu/kWh (HHV)		1393	LB/MWHR
TX-0758	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	Simple Cycle Combustion Turbine-MSS	0				
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	120	MW	USE OF NATURAL GAS. ENERGY EFFICIENCY DESIGN - USE OF INLET FOGGING/WET COMPRESSION, INSULATION BLANKETS TO REDUCE HEAT LOSS, AND FUEL GAS PREHEATING.	1394	LB/MWHR
CO-0075	PUEBLO AIRPORT GENERATING STATION	CO	5/30/2014	Turbine - simple cycle gas	375	MMBTU/H	Good Combustion Control	1600	LB/MWHR
TX-0757	INDECK WHARTON ENERGY CENTER	TX	5/12/2014	Simple Cycle Combustion Turbine, GE 7FA.05	0			1276	LB/MWHR
TX-0757	INDECK WHARTON ENERGY CENTER	TX	5/12/2014	Simple Cycle Combustion Turbine, SGT-5000F(5)	0			1337	LB/MWHR
ND-0030	LONESOME CREEK GENERATING STATION	ND	9/16/2013	Natural Gas Fired Simple Cycle Turbines	412	MMBTU/H	High efficiency turbines		
NY-0113	EDGEWOOD ENERGY LLC	NY	7/9/2013	Turbines - NG	0			1300	LB/MWHR
ND-0029	PIONEER GENERATING STATION	ND	5/14/2013	Natural gas-fired turbines	451	MMBTU/H			
ND-0028	R.M. HESKETT STATION	ND	2/22/2013	Combustion Turbine	986	MMBTU/H			

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Table E-14
NATURAL GAS FIRED SIMPLE CYCLE TURBINES, GREATER THAN 25 MW, PERMIT DATES FROM 01/01/2010 THROUGH 03/30/2023
LISTINGS FOR CO2 AND CO2e

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WV-0028	WAVERLY POWER PLANT	WV	3/13/2018	GE 7FA.004 Turbine	167.8	MW	Use of natural gas & use of GE 7FA.004	1300	LB/MWHR
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Two Simple Cycle Combustion Turbines	190	MW	Turbine-generator design and proper operation		
TX-0794	HILL COUNTY GENERATING FACILITY	TX	4/7/2016	Simple Cycle Turbine	171	MW		1434	LB/MWHR
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	(2) 60-MEGAWATT SIMPLE CYLCE COMBUSTION TURBINE, FIRING ULSD	120	MW	LIMITED USE OF ULSD. ENERGY EFFICIENCY DESIGN - USE OF INLET FOGGING/WET COMPRESSION, INSULATION BLANKETS TO REDUCE HEAT LOSS, AND FUEL GAS PREHEATING	1741	LB/MWHR

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMP ENGINES, (LESS THAN 2,000 HP) PERMIT DATE RANGE: 1/1/2018 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0365	MAPLE CREEK ENERGY LLC	IN	6/19/2023	Emergency generator	2012	hp		4.8	g/hp-hr
IN-0359	NUCOR STEEL	IN	3/30/2023	Emergency Generator (CC-GEN1)	3000	Horsepower	certified engine	4.8	g/hp-hr
AR-0177	NUCOR STEEL ARKANSAS	AR	11/21/2022	SN-230 Galvanizing Line No, 2 Emergency Generator	3634	Horsepower		4.18	g/hp-hr
OH-0387	INTEL OHIO SITE	OH	9/20/2022	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	5051	HP	Certified to meet Tier 2 standards and good combustion practices	4.78	g/hp-hr
OH-0387	INTEL OHIO SITE	OH	9/20/2022	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	275	HP	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices	2.99	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Emergency Engines	1250	kW		4.78	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Fire Water Pump Engine	320	horsepower		2.99	g/hp-hr
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUFPENGINE (North Plant): Fire Pump Engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	g/hp-hr
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUEMENGINE (North Plant): Emergency engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	4.78	g/hp-hr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUEMENGINE (South Plant): Emergency engine	1341	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	4.78	g/hp-hr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3	g/hp-hr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Generator Engine	2937	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.	4.8	g/hp-hr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Fired Water Pump Engine	355	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.	3	g/hp-hr
IN-0324	MIDWEST FERTILIZER COMPANY LLC	IN	5/6/2022	emergency generator EU 014a	3600	HP		4.42	g/hp-hr
WV-0033	MAIDSVILLE	WV	1/5/2022	Emergency Generator	2100	hp	Combustion Control (retarded timing and/or lean burn)	5.31	g/hp-hr
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour		4.78	g/hp-hr
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	Emergency Fire Pump Engine (347 HP)	2.46	MMBtu/hour		2.99	g/hp-hr

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND FIRE PUMPS, COMBUSTION TURBINES, WATER PUMP ENGINES, AND OTHER ENGINES, PERMIT DATE RANGE: 1/1/2018 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour		4.78	g/hp-hr
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	4/19/2021	Tunnel Furnace Emergency Generator (EP 08-06)	2937	HP	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	4.8	g/hp-hr
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	4/19/2021	Caster B Emergency Generator (EP 08-07)	2937	HP	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	4.8	g/hp-hr
MI-0448	GRAYLING PARTICLEBOARD	MI	12/18/2020	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	500	h/yr	Certified engines, limited operating hours	4.78	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.	3	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations.	4.8	g/hp-hr
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	19.4	gph	Good combustion practices, limit operation to 500 hours per year per engine	3.6	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-02 - North Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-03 - South Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-01 - Caster Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	g/hp-hr
LA-0370	WASHINGTON PARISH ENERGY CENTER	LA	4/27/2020	Emergency Fire Pump Engine (EQT0021, ENG-1)	1.1	MM BTU/hr	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII	3.32	g/hp-hr
WI-0302	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Diesel-Fired Fire Pump Engine (P04)	290	HP	Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight	5.69	g/hp-hr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUFPENGINE (Emergency engine-diesel fire pump	1.66	MMBTU/H	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3	g/hp-hr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUEMENGINE (diesel fuel emergency engine)	22.68	MMBTU/H	Good Combustion Practices and meeting NSPS Subpart IIII requirements	4.78	g/hp-hr
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGEMENGINE	1100	KW		5.3	g/hp-hr

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) TURBINES, WATER PUMPS, ENGINES, PERMIT DATE RANGE: 1/1/2018 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0317	RIVERVIEW ENERGY CORPORATION	IN	6/11/2019	Emergency generator EU-6006	2800	HP	Tier II diesel engine	4.78	g/hp-hr
OH-0379	PETMIN USA INCORPORATED	OH	2/6/2019	Emergency Generators (P005 and P006)	3131	HP	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	0.5	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower		2.99	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW		4.78	g/hp-hr
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	4.78	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	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	3	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	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	4.8	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	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	4.8	g/hp-hr
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	TX	9/23/2018	FIRE PUMP DIESEL ENGINE	214	kW	Meets EPA Tier 4 requirements	0.30	g/hp-hr
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Large Emergency Engines (>50kW)	5364	HP	Good Combustion and Operating Practices	4.18	g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	422	hp			g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour	Operate and maintain the engine according to the manufacturer's written instructions	4.78	g/hp-hr
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	Emergency Fire Pump Engine (347 HP)	8700	gal/year	Operate and maintain the engine according to the manufacturer's written instructions	2.99	g/hp-hr
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour	Operate and maintain the engine according to the manufacturer's written instructions	4.78	g/hp-hr

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL COMBUSTION TURBINES, WATER PUMP ENGINES, ECONOMIC LIMIT) PERMIT DATE RANGE: 1/1/2018 THROUGH 8/30/2023
LISTING FOR RBLC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2000	kW	State of the art combustion design.	4.78	g/hp-hr
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design.	2.99	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	4.78	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS IIII requirements.	4.78	g/hp-hr
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good combustion practices and NSPS IIII	2.99	g/hp-hr
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good combustion practices and NSPS Subpart IIII	2.99	g/hp-hr
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	g/hp-hr
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	Diesel-Fired Emergency Generators	0		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	4	g/hp-hr
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	P42 -Diesel Fired Emergency Generator	0		Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	4	g/hp-hr
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Diesel Generator (P003)	1860	HP	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	4.8	g/hp-hr
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Fire Pump (P004)	320	HP	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	3	g/hp-hr
MI-0434	FLAT ROCK ASSEMBLY PLANT	MI	3/22/2018	EUENGINE01 through EUENGINE08	3633	BHP	Good combustion practices.	4.78	g/hp-hr
MI-0434	FLAT ROCK ASSEMBLY PLANT	MI	3/22/2018	EUFIREPUMPENGS (2 emergency fire pump engines)	250	BHP	Good combustion practices.	3	g/hp-hr
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fueled fire pump (P006)	250	HP	Comply with NSPS 40 CFR 60 Subpart IIII	3	g/hp-hr
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fired generator (P007)	2682	HP	Comply with NSPS 40 CFR 60 Subpart IIII	4.8	g/hp-hr

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMPS, ENGINES, ETC. PERMIT DATE 1/1/2017 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	emergency generators (4 units)	13410	hp each	Comply with standards of 40 CFR 60 Subpart JJJJ	2	g/hp-hr
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Emergency Diesel Generator Engine (P001)	2206	HP	Good combustion design	4.8	g/hp-hr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Generators (2 identical, P004 and P005)	2206	HP	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.	4.77	g/hp-hr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Fire Pump (P006)	410	HP	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	3	g/hp-hr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency generator (P003)	1529	HP	State-of-the-art combustion design	4.8	g/hp-hr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency fire pump engine (P004)	300	HP	State-of-the-art combustion design	3	g/hp-hr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency generator (P003)	1529	HP	State-of-the-art combustion design	4.77	g/hp-hr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency fire pump engine (P004)	300	HP	State-of-the-art combustion design	2.98	g/hp-hr
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices	2.76	g/hp-hr
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	5.92	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Certified engines, limited operating hours.	4.78	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Certified engines, limited operating hours	0.99	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	460	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.30	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Generator (P009)	5000	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.50	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	4.42	g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	Complying with 40 CFR 60 Subpart IIII		

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Table E-15
EMERGENCY DIESEL GENERATORS (SIMPLE CYCLE) AND TURBINES, WATER PUMP ENGINES, AND EMERGENCY FIRE PUMP ENGINES PERMITTED FROM 1/1/2016 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS IIII requirements.	4.78	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump) - 260bhp	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	3	g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	0		complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)-165 bhp	500	H/YR	Good combustion practices.	3	g/hp-hr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency fire pump engine (P004)	311	HP	State-of-the-art combustion design	2.61	g/hp-hr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency generator (P003)	2947	HP	State-of-the-art combustion design	4.18	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Generator Engines	0			4.8	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Fire Pump Engine	422	bhp		3	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	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).	4.8	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	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).	3	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Certified engines, limited operating hours.	4.78	g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp	complying with 40 CFR 63 subpart ZZZZ		
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	1500	kw	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	4.18	g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP-327 bhp	327	bhp	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	2.84	g/hp-hr
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance	4.78	g/hp-hr
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP		3	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-15
EMERGENCY DIESEL GENERATORS (SIMPLE CYCLE) AND FIRE WATER PUMPS, COMMENCED AFTER 01/01/2010 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	2000	kwh	use of ultra low sulfur diesel a clean burning fuel.	6.44	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump -360 bhp	360	bhp	use of ULSD a clean burning fuel, and limited hours of operation	2.14	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Black start generator	3000	KW	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	g/hp-hr
LA-0292	HOLBROOK COMPRESSOR STATION	LA	1/22/2016	Emergency Generators No. 1 & No. 2	1341	HP	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	4.8	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine-315 hp	15	gal/hr		3	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			5.45	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	425	hp	GOOD COMBUSTION PRACTICES	9.5	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY GENERATOR	1490	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.78	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	305	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.99	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	2.99	g/hp-hr
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency fire pump engine (P004)	140	HP	State-of-the-art combustion design	2.62	g/hp-hr
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency generator (P003)	2346	HP	State-of-the-art combustion design	4.18	g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)	Complying with 40 CFR 60 Subpart IIII	3	g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)	Complying with 40 CFR 60 Subpart IIII	4.78	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMP ENGINES, (COMMERCIAL) PERMIT DATE RANGE: 1/1/2014 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.0218	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp		4.8	g/hp-hr
MI-0418	WARREN TECHNICAL CENTER	MI	1/14/2015	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	3490	KW	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.97	g/hp-hr
MI-0418	WARREN TECHNICAL CENTER	MI	1/14/2015	Four (4) emergency engines in FG-BACKUPGENS	2710	KW	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.32	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		4.8	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		3	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency generator (P002)	1100	KW	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	8.92	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency Fire Pump Engine (P003)	260	HP	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	3	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED AUXILIARY (EMERGENCY) ENGINES (TWO)	1500	KW	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.78	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED FIRE PUMP ENGINE	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL AND GOOD COMBUSTION PRACTICES	2.99	g/hp-hr
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMP ENGINES, AND COMPRESSOR ENGINES FROM RBLC DATABASE FOR PERMIT ISSUANCE DATES 1/1/2014 THROUGH 8/30/2023
LISTINGS FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.5	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Firewater Pump Engine	373	hp	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	2.61	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.50	g/hp-hr
MD-0043	PERRYMAN GENERATING STATION	MD	7/1/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	350	HP	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	3	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	3	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.83	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	2.91	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMPS, ENGINES, ETC. (LARGE) PERMIT DATE RANGE: 1/1/2013 THROUGH 8/30/2023
LISTING FOR NO2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	4.63	g/hp-hr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	4.63	g/hp-hr
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.8	g/hp-hr
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.8	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION	4.8	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	300	HP	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION	3	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	335	bhp		2.85	g/hp-hr
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	g/hp-hr
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	3	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	250	bhp		3.18	g/hp-hr
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine - 371 bhp	2.7	MMBTU/H		3	g/hp-hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	3	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-15
EMERGENCY DIESEL GENERATORS (SMALL) AND FIRE PUMPS, WATER PUMPS, COMPRESSORS, ENGINES, TURBINES, ETC. PERMIT DATE RANGE: 1/1/2013 THROUGH 8/30/2023
LISTINGS FOR NOX 2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency generator (P003)	1112	KW	Purchased certified to the standards in NSPS Subpart IIII	4.18	g/hp-hr
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency fire pump engine (P004)	400	HP	Purchased certified to the standards in NSPS Subpart IIII	2.61	g/hp-hr
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices	4.8	g/hp-hr
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	20.4	MMBTU/hr	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	4.78	g/hp-hr
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	380 HP Diesel Fired Pump Engine	2.3	MMBTU/hr	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	2.2	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	4.46	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	2.86	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	3	g/hp-hr
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	COMBUSTION CONTROL	4.99	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	2.57	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	2250	KW	Purchased certified to the standards in NSPS Subpart IIII	4.18	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP-450 bhp	3.25	MMBTU/H		0.66	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		1.46	g/hp-hr
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	4.98	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine	460	bhp		2.6	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-16
EMERGENCY DIESEL GENERATORS (SMALL GAS TURBINES, WATER PUMP ENGINES, AND OTHER EMERGENCY ENGINES) PERMITTED FROM 1/1/2018 THROUGH 8/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0365	MAPLE CREEK ENERGY LLC	IN	6/19/2023	Emergency generator	2012	hp		2.60	g/hp-hr
IN-0359	NUCOR STEEL	IN	3/30/2023	Emergency Generator (CC-GEN1)	3000	Horsepower	oxidation catalyst and certified engine	2.61	g/hp-hr
AR-0177	NUCOR STEEL ARKANSAS	AR	11/21/2022	SN-230 Galvanizing Line No, 2 Emergency Generator	3634	Horsepower		2.61	g/hp-hr
OH-0387	INTEL OHIO SITE	OH	9/20/2022	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	5051	HP	Certified to meet Tier 2 standards and good combustion practices	2.61	g/hp-hr
OH-0387	INTEL OHIO SITE	OH	9/20/2022	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	275	HP	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices	2.61	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Emergency Engines	1250	kW		2.61	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Fire Water Pump Engine	320	horsepower		2.61	g/hp-hr
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUEMENGINE (North Plant): Emergency engine	1341	HP	Good combustion practices and meeting NSPS IIII requirements.	2.61	g/hp-hr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUEMENGINE (South Plant): Emergency engine	1341	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	2.61	g/hp-hr
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUFPENGINE (North Plant): Fire Pump Engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements	2.60	g/hp-hr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good Combustion Practices and meeting NSPS Subpart IIII requirements	2.60	g/hp-hr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Generator Engine	2937	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.	2.60	g/hp-hr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Fired Water Pump Engine	355	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.	2.60	g/hp-hr
IN-0324	MIDWEST FERTILIZER COMPANY LLC	IN	5/6/2022	emergency generator EU 014a	3600	HP		2.61	g/hp-hr
WV-0033	MAIDSVILLE	WV	1/5/2022	Emergency Generator	2100	hp	Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine	0.42	g/hp-hr
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour		2.61	g/hp-hr

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Table E-16

EMERGENCY DIESEL GENERATORS (≤ 500 HP) AND TURBINES, WATER PUMPS, ENGINES, ETC. PERMITTED FROM 1/1/2018 THROUGH 8/30/2023

LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	FL	6/7/2021	Emergency Fire Pump Engine (347 HP)	2.46	MMBtu/hour		2.61	g/hp-hr
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	4/19/2021	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	2922	HP	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	2.60	g/hp-hr
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	4/19/2021	Tunnel Furnace Emergency Generator (EP 08-06)	2937	HP	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	2.60	g/hp-hr
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	4/19/2021	Caster B Emergency Generator (EP 08-07)	2937	HP	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	2.60	g/hp-hr
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices	2.60	g/hp-hr
MI-0448	GRAYLING PARTICLEBOARD	MI	12/18/2020	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	500	h/yr	Good design and combustion practices	2.61	g/hp-hr
MI-0448	GRAYLING PARTICLEBOARD	MI	12/18/2020	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	500	h/yr	Good Design and Combustion Practices	2.61	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.	2.60	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	Operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations.	2.60	g/hp-hr
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	19.4	gph	Good combustion practices, limit operation to 500 hours per year per engine	3.30	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-02 - North Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-03 - South Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-01 - Caster Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	g/hp-hr
OH-0383	PETMIN USA INCORPORATED	OH	7/17/2020	Emergency Generators (P005 and P006)	3131	HP	Tier IV engine Good combustion practices	2.60	g/hp-hr
LA-0370	WASHINGTON PARISH ENERGY CENTER	LA	4/27/2020	Emergency Fire Pump Engine (EQT0021, ENG-1)	157	HP	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII	1.16	g/hp-hr

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Table E-16
EMERGENCY DIESEL GENERATORS (SMALL) AND FIRE PUMPS, WATER PUMPS, COMPRESSOR ENGINES, AND TURBINES, NATURAL GAS FIRED (SMALL) PERMIT DATE RANGE: 1/1/2018 THROUGH 8/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0302	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Diesel-Fired Fire Pump Engine (P04)	290	HP	Good combustion practices	0.52	g/hp-hr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUEMENGINE (diesel fuel emergency engine)	22.68	MMBTU/H	Good Combustion Practices and meeting NSPS Subpart IIII requirements	2.61	g/hp-hr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUFPENGINE (Emergency engine-diesel fire pump	1.66	MMBTU/H	Good Combustion Practices and meeting NSPS Subpart IIII requirements	2.60	g/hp-hr
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGEMENGINE	1100	KW		0.15	g/hp-hr
IN-0317	RIVERVIEW ENERGY CORPORATION	IN	6/11/2019	Emergency generator EU-6006	2800	HP	Tier II diesel engine	2.61	g/hp-hr
AR-0171	NUCOR STEEL ARKANSAS	AR	2/14/2019	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	1073	bhp	Good operating practices.	2.99	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower		2.61	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	1500	kW		2.61	g/hp-hr
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and will be NSPS compliant.	2.61	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	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	2.61	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	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	2.60	g/hp-hr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	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	2.60	g/hp-hr
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	2.5	MMBTU/H	Good combustion practices.	2.60	g/hp-hr
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	TX	9/23/2018	FIRE PUMP DIESEL ENGINE	214	kW	Meets EPA Tier 4 requirements	2.67	g/hp-hr
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	Large Emergency Engines (>50kW)	5364	HP	Good Combustion and Operating Practices.	2.61	g/hp-hr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	0				
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	0				

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (SMALL GAS TURBINES, WATER PUMP ENGINES, ETC.) PERMITTED FROM 1/1/2018 THROUGH 8/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	1,500 kW Emergency Diesel Generator	14.82	MMBtu/hour	Operate and maintain the engine according to the manufacturer's written instructions	2.61	g/hp-hr
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	FL	7/27/2018	Emergency Fire Pump Engine (347 HP)	8700	gal/year	Operate and maintain the engine according to the manufacturer's written instructions	2.61	g/hp-hr
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2	MW	State of the art combustion design.	2.61	g/hp-hr
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	State of the art combustion design.	2.61	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.61	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices and meeting NSPS IIII requirements.	2.61	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.60	g/hp-hr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.60	g/hp-hr
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Compliance with 40 CFR 60 Subpart IIII		
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Compliance with 40 CFR 60 Subpart IIII		
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.60	g/hp-hr
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	500	HR/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.60	g/hp-hr
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.60	g/hp-hr
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	Diesel-Fired Emergency Generators	0		Good Combustion Practices	0.45	g/hp-hr
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	P42 -Diesel Fired Emergency Generator	0		Good Combustion Practices	0.45	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMPS, ENGINES, ETC. PERMIT DATE 01/1/2018 THROUGH 8/30/2023
LISTINGS FOR PC 2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Fire Pump (P004)	320	HP	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	2.59	g/hp-hr
LA-0350	BENTELER STEEL TUBE FACILITY	LA	3/28/2018	emergency generators (3 units) EQT0039, EQT0040, EQT0041	0		Comply with 40 CFR 60 Subpart IIII		
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fueled fire pump (P006)	250	HP	Comply with NSPS 40 CFR 60 Subpart IIII	2.54	g/hp-hr
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fired generator (P007)	2682	HP	Comply with NSPS 40 CFR 60 Subpart IIII	2.60	g/hp-hr
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Emergency Diesel Generator Engine (P001)	2206	HP	Good combustion design	2.60	g/hp-hr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Generators (2 identical, P004 and P005)	2206	HP	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.	2.61	g/hp-hr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Fire Pump (P006)	410	HP	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.	2.61	g/hp-hr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency generator (P003)	1529	HP	State-of-the-art combustion design	2.61	g/hp-hr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency fire pump engine (P004)	300	HP	state of the art combustion design	2.62	g/hp-hr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency fire pump engine (P004)	300	HP	State-of-the-art combustion design	2.62	g/hp-hr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency generator (P003)	1529	HP	State-of-the-art combustion design	2.61	g/hp-hr
PA-0313	FIRST QUALITY TISSUE LOCK HAVEN PLT	PA	7/27/2017	Emergency Generator	2500	bhp		2.61	g/hp-hr
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices	2.46	g/hp-hr
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	0.16	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	500	H/YR	Good design and combustion practices.	2.61	g/hp-hr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	500	H/YR	Good design and combustion practices.	2.61	g/hp-hr
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	460	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	2.56	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-16
EMERGENCY DIESEL GENERATORS (SMALL) AND TURBINES, WATER PUMPS, ENGINES, PERMIT DATE FROM 1/1/2016 THROUGH 8/30/2023
LISTINGS FOR PM2.5

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Generator (P009)	5000	HP	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	2.61	g/hp-hr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	Complying with 40 CFR 60 Subpart IIII		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	Complying with 40 CFR 60 Subpart IIII		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	22.68	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.61	g/hp-hr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	1.66	MMBTU/H	Good combustion practices and meeting NSPS Subpart IIII requirements.	2.60	g/hp-hr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	0		complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	500	H/YR	Good combustion practices.	3.70	g/hp-hr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency fire pump engine (P004)	311	HP	State-of-the-art combustion design	2.61	g/hp-hr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency generator (P003)	2947	HP	State-of-the-art combustion design	2.61	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Generator Engines	0			2.61	g/hp-hr
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Emergency Fire Pump Engine	0			2.61	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	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).	2.60	g/hp-hr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	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).	2.60	g/hp-hr
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	500	H/YR	Good design and combustion practices.	2.61	g/hp-hr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp	complying with 40 CFR 63 subpart ZZZZ		

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation (<= 100 H/YR)	2.62	g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	2.59	g/hp-hr
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	0		Good Combustion Practices/Maintenance	2.61	g/hp-hr
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	0		Good Combustion Practices/Maintenance	2.60	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ultra low sulfur diesel oil a clean burning fuel	0.59	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation	1.39	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Black start generator	3000	KW	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.60	g/hp-hr
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.53	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	15	gal/hr		0.50	g/hp-hr
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	0			0.60	g/hp-hr
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	EMERGENCY FIRE PUMP ENGINE	0		GOOD COMBUSTION PRACTICES	2.01	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY GENERATOR	1490	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	305	HP	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	2.61	g/hp-hr
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency fire pump engine (P004)	140	HP	State-of-the-art combustion design	3.73	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency generator (P003)	2346	HP	State-of-the-art combustion design	2.61	g/hp-hr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)	Complying with 40 CFR 60 Subpart IIII		
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)	Complying with 40 CFR 60 Subpart IIII		
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	TX	4/1/2015	Emergency Diesel Generator	1500	hp	Minimized hours of operations Tier II engine	0.01	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp		2.60	g/hp-hr
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Fine Water Pumps	610	hp		2.60	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		2.60	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		2.60	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency generator (P002)	1474	HP	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	2.61	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency Fire Pump Engine (P003)	260	HP	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	1.20	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency generator (P002)	1100	KW	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	2.61	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED AUXILIARY (EMERGENCY) ENGINES (TWO)	1500	KW	EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
MD-0046	KEYS ENERGY CENTER	MD	10/31/2014	DIESEL-FIRED FIRE PUMP ENGINE	300	HP	EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL AND GOOD COMBUSTION PRACTICES	2.61	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	FL	9/16/2014	Emergency Diesel Engine	3300	hp	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure		
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	2.61	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Firewater Pump Engine	373	hp	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	2.61	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	EMERGENCY GENERATOR	1550	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT	2.60	g/hp-hr
MD-0044	COVE POINT LNG TERMINAL	MD	6/9/2014	5 EMERGENCY FIRE WATER PUMP ENGINES	350	HP	GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT	3.00	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.60	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	2.60	g/hp-hr
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	2.60	g/hp-hr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	2.61	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-16
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	2.61	g/hp-hr
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.63	g/hp-hr
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	2.63	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY GENERATOR	1500	KW	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.60	g/hp-hr
MD-0041	CPV ST. CHARLES	MD	4/23/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	300	HP	USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.60	g/hp-hr
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Four 3100 kW black start emergency generators	2.32	MMBtu/hr (HHV) per engine	Good combustion practice	2.61	g/hp-hr
FL-0346	LAUDERDALE PLANT	FL	4/22/2014	Emergency fire pump engine (300 HP)	29	MMBTU/H	Good combustion practice.	2.61	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	0			2.60	g/hp-hr
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	0			2.60	g/hp-hr
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY GENERATOR 1	2250	KW	USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR	2.60	g/hp-hr
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	477	HP	USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR	2.60	g/hp-hr
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/7/2014	Emergency diesel fire pump	0			2.60	g/hp-hr
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	7.4	MMBTU/H		2.60	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-16
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR CO

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	2.7	MMBTU/H		2.60	g/hp-hr
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	3.70	g/hp-hr
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency generator (P003)	1490.08	HP	Purchased certified to the standards in NSPS Subpart IIII	2.61	g/hp-hr
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency fire pump engine (P004)	400	HP	Purchased certified to the standards in NSPS Subpart IIII	2.61	g/hp-hr
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1000	kW	Good combustion practices.	2.60	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	B-HP	GOOD COMBUSTION PRACTICES	2.61	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	2.60	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	2.60	g/hp-hr
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	COMBUSTION CONTROL.	0.00	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP	Purchased certified to the standards in NSPS Subpart IIII	2.57	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	3015	HP	Purchased certified to the standards in NSPS Subpart IIII	2.61	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	3.25	MMBTU/H		0.92	g/hp-hr
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	7.8	MMBTU/H		0.86	g/hp-hr
KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	KS	3/18/2013	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	182	BHP	utilize efficient combustion/design technology	1.32	g/hp-hr
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Emergency diesel generator- 2200 kW	500	hrs/yr	good combustion practices	2.61	g/hp-hr
VA-0321	BRUNSWICK COUNTY POWER STATION	VA	3/12/2013	Diesel Fire water pump 376 bhp	500	h/yr	good combustion practices	0.67	g/hp-hr
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	PA	1/31/2013	Fire Pump Engine - 460 BHP	0			0.50	g/hp-hr

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Table E-17

EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023

LISTINGS FOR VOC

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY GENERATOR DIESEL	0	100 H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	0.13	g/hp-hr
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	EMERGENCY DIESEL FIRE PUMP	100	H/YR	Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation	0.16	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ULSD a clean burning fuel, and limited hours of operation	0.17	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Emergency Diesel Fire Pump	100	H/YR	use of ULSD a clean burning fuel, and limited hours of operation	0.13	g/hp-hr
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Diesel Fired Emergency Generator	44	H/YR	use of ULSD a clean burning fuel, and limited hours of operation	0.17	g/hp-hr

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Table E-18
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR TPM

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	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.	0.15	g/hp-hr
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	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.	0.15	g/hp-hr
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	19.4	gph	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine	0.19	g/hp-hr
WI-0302	WPL- RIVERSIDE ENERGY CENTER	WI	2/28/2020	Diesel-Fired Fire Pump Engine (P04)	290	HP	Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight	0.17	g/hp-hr
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGEMENGINE	1100	KW	Good combustion practices and ultra low sulfur diesel	0.04	g/hp-hr
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	P42 -Diesel Fired Emergency Generator	2346	bhp	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	0.13	g/hp-hr
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Diesel Generator (P003)	1860	HP	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0.15	g/hp-hr
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Fire Pump (P004)	320	HP	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0.15	g/hp-hr
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Clean Fuel and Good Combustion Practices	0.14	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Three 3300-kW ULSD emergency generators	0		Use of clean fuel	0.15	g/hp-hr
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	One 422-hp emergency fire pump engine	0		Use of clean fuel	0.15	g/hp-hr
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	29	MMBTU/H	Low-emitting fuel and certified engine	0.15	g/hp-hr

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
IN-0365	MAPLE CREEK ENERGY LLC	IN	6/19/2023	Emergency generator	2012	hp			
IN-0359	NUCOR STEEL	IN	3/30/2023	Emergency Generator (CC-GEN1)	3000	Horsepower	Good engineering design and manufacturer's recommended operating and maintenance procedures.	519.5	g/hp-hr
IN-0359	NUCOR STEEL	IN	3/30/2023	Emergency Generator (CC-GEN2)	500	Horsepower	Good engineering design and manufacturer's recommended operating and maintenance procedures.	519.5	g/hp-hr
AR-0177	NUCOR STEEL ARKANSAS	AR	11/21/2022	SN-230 Galvanizing Line No, 2 Emergency Generator	3634	Horsepower			
OH-0387	INTEL OHIO SITE	OH	9/20/2022	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	5051	HP	Good combustion practices and proper maintenance and operation	516.6	g/hp-hr
OH-0387	INTEL OHIO SITE	OH	9/20/2022	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	275	HP	Good combustion practices and proper maintenance and operation	516.6	g/hp-hr
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Emergency Engines	1863	HP			
IL-0133	LINCOLN LAND ENERGY CENTER	IL	7/29/2022	Fire Water Pump Engine	320	horsepower			
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUFPENGINE (North Plant): Fire Pump Engine	300	HP	Good combustion practices	85.6	ton/yr
MI-0451	MEC NORTH, LLC	MI	6/23/2022	EUEMENGINE (North Plant): Emergency engine	1341	HP	Good combustion practices	383	ton/yr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUEMENGINE (South Plant): Emergency engine	1341	HP	Good combustion practices	383	ton/yr
MI-0452	MEC SOUTH, LLC	MI	6/23/2022	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices.	85.6	ton/yr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Generator Engine	2937	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.	519.5	g/hp-hr
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	LA	6/3/2022	Emergency Diesel Fired Water Pump Engine	355	hp	Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.	519.5	g/hp-hr
IN-0324	MIDWEST FERTILIZER COMPANY LLC	IN	5/6/2022	emergency generator EU 014a	3600	HP			
MI-0447	LBWL--ERICKSON STATION	MI	1/7/2021	EUFPRICE--A 315 HP diesel fueled emergency engine	315	HP	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	20	ton/yr
MI-0448	GRAYLING PARTICLEBOARD	MI	12/18/2020	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	2235	hp	Good Combustion and Design Practices	479.0	g/hp-hr

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0448	GRAYLING PARTICLEBOARD	MI	12/18/2020	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	745	hp	Good Combustion and Design Practices	209	ton/yr
VA-0333	NORFOLK NAVAL SHIPYARD	VA	12/9/2020	One (1) emergency engine generator	2220	HP			

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Fire Pump (P06)	282	HP	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.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Emergency Diesel Generator (P07)	1490	HP	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.		
AK-0085	GAS TREATMENT PLANT	AK	8/13/2020	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	335	hp	Good combustion practices and limit operation to 500 hours per year per engine	519.5	g/hp-hr
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-02 - North Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-03 - South Water System Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-04 - Emergency Fire Water Pump	920	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 11-01 - Melt Shop Emergency Generator	260	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 11-02 - Reheat Furnace Emergency Generator	190	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-07 - Air Separation Plant Emergency Generator	700	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 10-01 - Caster Emergency Generator	2922	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 11-03 - Rolling Mill Emergency Generator	440	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
KY-0110	NUCOR STEEL BRANDENBURG	KY	7/23/2020	EP 11-04 - IT Emergency Generator	190	HP	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.		
OH-0383	PETMIN USA INCORPORATED	OH	7/17/2020	Diesel-fired emergency fire pumps (2) (P009 and P010)	3131	HP	Tier IV engine and good combustion practices	521.6	g/hp-hr
LA-0370	WASHINGTON PARISH ENERGY CENTER	LA	4/27/2020	Emergency Fire Pump Engine (EQT0021, ENG-1)	157	hp	Good combustion practices in order to comply with 40 CFR 60 Subpart IIII	9	ton/yr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUFPENGINE (Emergency engine-diesel fire pump	266	bhp	Good combustion practices	13.58	ton/yr
MI-0445	INDECK NILES, LLC	MI	11/26/2019	EUEMENGINE (diesel fuel emergency engine)	2922	HP	Good combustion practices	928	ton/yr
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	8/21/2019	FGEMENGINE	1639	HP			
IN-0317	RIVERVIEW ENERGY CORPORATION	IN	6/11/2019	Emergency generator EU-6006	2800	HP	Tier II diesel engine	811	ton/yr
AR-0171	NUCOR STEEL ARKANSAS	AR	2/14/2019	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	1073	bhp	Good operating practices.	517.6	g/hp-hr
OH-0379	PETMIN USA INCORPORATED	OH	2/6/2019	Emergency Generators (P005 and P006)	3131	HP	Tier IV engine Good combustion practices	526.6	g/hp-hr
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Firewater Pump Engine	420	horsepower			
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Emergency Engine	2235	HP			
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUEMGD1--A 1500 HP diesel fueled emergency engine	1500	HP	Good combustion practices and energy efficiency measures.	406	ton/yr
MI-0441	LBWL--ERICKSON STATION	MI	12/21/2018	EUFPRICE--A 315 HP diesel fueled emergency engine	315	HP	Good combustion practices and energy efficiency measures.	20	ton/yr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Firewater Pumps (P005 and P006)	402	HP	good operating practices (proper maintenance and operation)	23	ton/yr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	Emergency Diesel-fired Generator Engine (P007)	3353	HP	good operating practices (proper maintenance and operation)	200	ton/yr
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	12/21/2018	1,000 kW Emergency Generators (P008 - P010)	1341	HP	good operating practices (proper maintenance and operation)	80	ton/yr
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	TX	9/23/2018	FIRE PUMP DIESEL ENGINE	319	HP	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		

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0331	CALCASIEU PASS LNG PROJECT	LA	9/21/2018	5 Large Emergency Engines (>50kW)	5364	HP	Good Combustion of Practices and Good Operation and Maintenance Practices	296.2	ton/yr
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Emergency Engines	2235	HP			
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Firewater Pump Engine	422	HP			
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUEMENGINE: Emergency engine	2980	HP	Energy efficient design.	161	ton/yr
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFPENGINE: Fire pump engine	399	BHP	Energy efficient design	86	ton/yr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (South Plant): Fire pump engine	300	HP	Good combustion practices.	85.6	ton/yr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (North Plant): Emergency Engine	1341	HP	Good combustion practices.	383	ton/yr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUFPENGINE (North Plant): Fire pump engine	300	HP	Good combustion practices.	85.6	ton/yr
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MI	6/29/2018	EUEMENGINE (South Plant): Emergency Engine	1341	HP	Good combustion practices.	383	ton/yr
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39A	375	HP	Good Combustion Practices	28	ton/yr
LA-0328	PLAQUEMINES PLANT 1	LA	5/2/2018	Emergency Diesel Engine Pump P-39B	300	HP	Good Combustion Practices	28	ton/yr
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Diesel GEN	500	H/YR	use of S15 ULSD and high efficiency design and operation	981	ton/yr
VA-0328	C4GT, LLC	VA	4/26/2018	Emergency Fire Water Pump	315	BHP	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	1040	ton/yr
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	Diesel-Fired Emergency Generators	3248	HP	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices		
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	WI	4/24/2018	P42 -Diesel Fired Emergency Generator	2346	bhp	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel		
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Diesel Generator (P003)	1860	HP	Efficient design and proper maintenance and operation	109.2	ton/yr
OH-0377	HARRISON POWER	OH	4/19/2018	Emergency Fire Pump (P004)	320	HP	Efficient design and proper maintenance and operation	18.67	ton/yr
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fueled fire pump (P006)	250	HP	Equipment design and maintenance requirements	519.5	g/hp-hr
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	2/9/2018	Emergency diesel-fired generator (P007)	2682	HP	Equipment design and maintenance requirements	519.5	g/hp-hr

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	11/7/2017	Emergency Diesel Generator Engine (P001)	2206	HP	Efficient design	116.8	ton/yr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Generators (2 identical, P004 and P005)	2206	HP	good operating practices (proper maintenance and operation)	120	ton/yr
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Emergency Fire Pump (P006)	410	HP	good operating practices (proper maintenance and operation)	29	ton/yr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency generator (P003)	1529	HP	state of the art combustion design	445	ton/yr
OH-0372	OREGON ENERGY CENTER	OH	9/27/2017	Emergency fire pump engine (P004)	300	HP	State-of-the-art combustion design	87	ton/yr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency generator (P003)	1529	HP	Efficient design	445	ton/yr
OH-0370	TRUMBULL ENERGY CENTER	OH	9/7/2017	Emergency fire pump engine (P004)	300	HP	Efficient design	87	ton/yr
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Fire Pump Diesel Internal Combustion Engines	252	hp	Good Combustion Practices	216	ton/yr
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	1474	horsepower	Compliance with NSPS Subpart IIII	84	ton/yr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	2235	hp	Good combustion and design practices.	209	ton/yr
MI-0425	GRAYLING PARTICLEBOARD	MI	5/9/2017	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	2235	hp	Good combustion and design practices.	70	ton/yr
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Fire Pump Diesel Engine (P008)	460	HP	good combustion control and operating practices and engines designed to meet the standards of 40 CFR Part 60, Subpart IIII	123	ton/yr
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Emergency Generator (P009)	5000	HP	good combustion control and operating practices and engines designed to meet the standards of 40 CFR Part 60, Subpart IIII	1289	ton/yr
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	3/23/2017	EMERGENCY GENERATORS (EU014A AND EU-014B)	3600	HP EACH	GOOD COMBUSTION PRACTICES	526.2	g/bhp-hr
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	firewater pump engines (8 units)	460	hp	good combustion practices		
LA-0316	CAMERON LNG FACILITY	LA	2/17/2017	emergency generator engines (6 units)	3353	hp	good combustion practices		
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUEMENGINE (Diesel fuel emergency engine)	2922	HP	Good combustion practices	928	ton/yr
MI-0423	INDECK NILES, LLC	MI	1/4/2017	EUFPENGINE (Emergency engine--diesel fire pump)	260	bhp	Good combustion practices	13.58	ton/yr
LA-0317	METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Emergency Generator Engines (4 units)	2346	HP	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ		

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFPENGINE (Emergency engine--diesel fire pump)	165	hp	Good combustion practices.	55.6	ton/yr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency fire pump engine (P004)	311	HP	Efficient design	90	ton/yr
OH-0367	SOUTH FIELD ENERGY LLC	OH	9/23/2016	Emergency generator (P003)	2947	HP	Efficient design	858	ton/yr
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Generator 1	2584	HP	Good combustion practices		
LA-0313	ST. CHARLES POWER STATION	LA	8/31/2016	SCPS Emergency Diesel Firewater Pump 1	282	HP	Good combustion practices		
MI-0421	GRAYLING PARTICLEBOARD	MI	8/26/2016	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	2384	hp	Good combustion and design practices.	223	ton/yr
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel Firewater pump engines (6 units)	425	hp			
LA-0314	INDORAMA LAKE CHARLES FACILITY	LA	8/3/2016	Diesel emergency generator engine - EGEN	350	hp			
LA-0305	LAKE CHARLES METHANOL FACILITY	LA	6/30/2016	Diesel Engines (Emergency)	4023	hp	Complying with 40 CFR 60 Subpart IIII		
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	4023	HP	Good Combustion Practices/Maintenance	519.5	g/hp-hr
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	DIESEL-FIRED WATER PUMP 376 bph (1)	376	bhp	Good Combustion Practices/Maintenance	104	ton/yr
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Compression ignition RICE emergency fire pump	197	HP			
NY-0103	CRICKET VALLEY ENERGY CENTER	NY	2/3/2016	Emergency fire pump	460	hp	Good combustion practice and efficient engine design.	115	ton/yr
LA-0292	HOLBROOK COMPRESSOR STATION	LA	1/22/2016	Emergency Generators No. 1 & No. 2	1341	HP			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	Fire pump engine	315	HP			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	PA	12/23/2015	2000 kW Emergency Generator	2980	HP			
FL-0354	LAUDERDALE PLANT	FL	8/25/2015	Emergency fire pump engine, 300 HP	300	HP	Lowest-emitting available fuel		
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency fire pump engine (P004)	140	HP	Efficient design	41	ton/yr
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	8/25/2015	Emergency generator (P003)	2346	HP	Efficient design	683	ton/yr
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Firewater Pump Engines	288	hp (each)			

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0309	BENTELER STEEL TUBE FACILITY	LA	6/4/2015	Emergency Generator Engines	2922	hp (each)			
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Emergency Camp Generators	2695	hp			
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Airstrip Generator Engine	490	hp			
AK-0082	POINT THOMSON PRODUCTION FACILITY	AK	1/23/2015	Fine Water Pumps	610	hp			
OK-0164	MIDWEST CITY AIR DEPOT	OK	1/8/2015	Diesel-Fueled Fire Pump Engines	300	HP	1. Good Combustion Practices. 2. Efficient Design.	14.7	ton/yr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Fire Pump Engine	251	HP		558.42	g/hp-hr
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	WV	11/21/2014	Emergency Generator	2015.7	HP		543.68	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency generator (P002)	1639	HP	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	524.7	g/hp-hr
OH-0363	NTE OHIO, LLC	OH	11/5/2014	Emergency Fire Pump Engine (P003)	260	HP	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	523.4	g/hp-hr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Emergency Generator	3755	HP	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	432	ton/yr
IL-0114	CRONUS CHEMICALS, LLC	IL	9/5/2014	Firewater Pump Engine	373	hp	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	72	ton/yr
WY-0076	ROCK SPRINGS FERTILIZER COMPLEX	WY	7/1/2014	Fire Water Pump Engine	200	HP	limited to 500 hours of operation per year	526.2	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	FIRE PUMP	500	HP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	526.4	g/hp-hr
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	6/4/2014	DIESEL FIRED EMERGENCY GENERATOR	3600	BHP	GOOD COMBUSTION PRACTICES	526.4	g/hp-hr

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	LA	5/23/2014	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)	500	HP	Compliance with 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage	10	ton/yr
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	LA	5/23/2014	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	2682	HP	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	56	ton/yr
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	LA	5/23/2014	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	2682	HP	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.	56	ton/yr
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 1	5364	HP	Proper design and operation; energy efficiency measures		
LA-0315	G2G PLANT	LA	5/23/2014	Emergency Diesel Generator 2	5364	HP	Proper design and operation; energy efficiency measures		
TX-0757	INDECK WHARTON ENERGY CENTER	TX	5/12/2014	Firewater Pump Engine	175	hp			
ID-0021	MAGNIDA	ID	4/21/2014	EMERGENCY GENERATOR ENGINE	2980	HP			
ID-0021	MAGNIDA	ID	4/21/2014	FIRE WATER PUMP ENGINE	500	brake horsepower			
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Fire Pump	335	BHP			
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	PR	4/10/2014	Emergency Diesel Generator	670	BHP			
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Emergency Engine/Generator	1118	hp			

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Table E-19
EMERGENCY DIESEL GENERATORS (1341–5364 hp) AND FIRE WATER PUMP ENGINES (100–500 hp), PERMIT DATES FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	MA	1/30/2014	Fire Pump Engine	371	bhp			
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Emergency Engine --Diesel Fire Pump (EUFPENGINE)	165	HP	Good combustion practices	0.29	ton/yr
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency generator (P003)	1657	HP			
OH-0360	CARROLL COUNTY ENERGY	OH	11/5/2013	Emergency fire pump engine (P004)	400	HP			
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	FG-EMGEN7-8; Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion engines	1490	HP	Good combustion practices.	865.7	ton/yr
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	2000 KW Diesel Fired Emergency Generator Engine	2980	hp	Good combustion practices		
LA-0308	MORGAN CITY POWER PLANT	LA	9/26/2013	380 HP Diesel Fired Pump Engine	380	HP	Good combustion practices		
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY WATER PUMP	481	BHP	GOOD COMBUSTION PRACTICES	527.4	g/hp-hr
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	9/25/2013	DIESEL-FIRED EMERGENCY GENERATOR	4690	BHP	GOOD COMBUSTION PRACTICES	526.4	g/hp-hr
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	EU-FPENGINE: Diesel fuel fired emergency backup fire pump	315	hp nameplate	Proper combustion design and ultra low sulfur diesel fuel.	15.6	ton/yr
OK-0154	MOORELAND GENERATING STA	OK	7/2/2013	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	1341	HP	A TIER 3 CERTIFIED ENGINE OPERATED < 100 HR/YR.	549.3	g/hp-hr
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency fire pump engine	300	HP			
OH-0352	OREGON CLEAN ENERGY CENTER	OH	6/18/2013	Emergency generator	3353	HP			
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY FIREWATER PUMP	450	bhp			
PA-0291	HICKORY RUN ENERGY STATION	PA	4/23/2013	EMERGENCY GENERATOR	1135	bhp			

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TABLE E-20
EMERGENCY DIESEL GENERATORS (DIESEL FUEL STORAGE TANKS) PERMITTED ENGINES (10/1/2018) THROUGH 10/15/2023 FROM 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0124	EL DORADO SAWMILL	AR	8/3/2015	THREE DIESEL STORAGE TANKS SN-15	0		TANKS ARE LIGHT COLOR	1.752	TONS/YR
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	IA	7/12/2013	Diesel Belly Tanks	45000	gal/yr		0.100	TONS/YR
IN-0312	LEHIGH CEMENT COMPANY LLC	IN	6/27/2019	Diesel tanks	1400	GALLONS (EACH)	good design and operating practices		TONS/YR
IN-0318	RIVERVIEW ENERGY CORPORATION	IN	6/11/2019	Diesel product tanks	0		Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.	2.290	TONS/YR
IN-0318	RIVERVIEW ENERGY CORPORATION	IN	6/11/2019	Diesel fuel tank T17	0		Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.	0.011	TONS/YR
LA-0363	HOLDEN WOOD PRODUCTS MILL	LA	10/2/2019	Diesel Storage Tank	150000	gallons/yr	Good Tank Design and Submerged Fill Page.		TONS/YR
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	TX	9/23/2018	Storage Tanks - Very Low Vapor Pressure Non Gasoline Automotive Fluids - Gear Lube, Engine Oil, Diesel fuel, Urea, ATF Etc. <20,000 gal each	0		White fixed roof storage tanks equipped with a submerged fill pipe. use of drain dry construction is required to minimize the emissions from tank entry and inspection.		TONS/YR

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Table E-21

EMERGENCY DIESEL GENERATOR (1341-1586 hp) AND FIRE WATER PUMP ENGINES (500-1,001 hp), 1 HR TO LESS THAN 2 HRS/DAY, 8/30/2013 THROUGH 8/30/2023

LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three Gas Heaters	10	MMBtu/hr		0.011	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Low-NOx burners, only use pipeline quality natural gas, maintain and operate according to manufacturer's recommendations.	0.049	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Low-NOx burners, only combust pipeline quality natural gas, and operate and maintain the heater according to the manufacturer's recommendations.	0.049	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only use natural gas in each heater.	0.098	LB/MMBTU
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.049	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Low NOx burners	0.011	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Fuel Heater	13	mmBtu/hour	Low-NOx combustion technology	0.011	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Low-NOx burners	0.011	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low NOx burner	0.036	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low NOx burner	0.037	LB/MMBTU
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	Ultra Low NOx burners		
FL-0363	DANIA BEACH ENERGY CENTER	FL	12/4/2017	Two natural gas heaters	9.9	MMBtu/hr	Manufacturer certification	0.100	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Low-NOx gas burner	0.020	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.098	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.149	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Fuel Heater	15	mmbtu/hr		0.033	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Dew point heater 13.8	0			0.011	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Dew point heater 3.2	3.2	MMBtu/hr		0.035	LB/MMBTU

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Table E-21
EMERGENCY DIESEL GENERATOR (1364 hp) AND FIRE WATER PUMP ENGINES (500 hp), PERMIT DATES 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	ultra low-NOx burners	0.011	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.100	LB/MMBTU
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Two natural gas heaters	10	MMBtu/hr	Must have NOx emission design value less than 0.1 lb/MMBtu	0.100	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	WI	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices, fire only pipeline quality natural gas	0.100	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.011	LB/MMBTU
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	heater	3	MMBTU/H		0.100	LB/MMBTU
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	fuel gas heater	18	MMBTU/H		0.100	LB/MMBTU
MD-0041	CPV ST. CHARLES	MD	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	heater	5.5	MMBTU/H		0.036	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	dew point heater	13.32	mmBtu/hr		0.013	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.049	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.035	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices.	0.149	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.150	LB/MMBTU
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Gas heater	0		Forced draft low NOx burner.	0.058	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-21
EMERGENCY DIESEL GENERATORS (1341-1586 HP) AND FIRE WATER PUMP ENGINES (300-500 HP), PERMIT DATES 1/28/2008 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Low NOx burners	0.060	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.085	LB/MMBTU

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Table E-12

EMERGENCY DIESEL GENERATORS (1MW-1500 HP) AND FIRE WATER PUMPS PERMITTED FROM 1/01/2013 THROUGH 8/30/2023

LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three Gas Heaters	10	MMBtu/hr		0.080	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain the process according to manufacturer's recommendations.	0.080	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain heater according to the manufacturer's recommendations.	0.080	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.082	LB/MMBTU
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.041	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	good combustion practices, operator training, and proper emissions unit design, construction and maintenance.	0.037	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	0.080	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	0.006	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Good combustion controls.	0.037	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Good combustion controls	0.037	LB/MMBTU
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	good combustion practices	0.036	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.055	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.082	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.111	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Dew point heater 13.8	0			0.080	LB/MMBTU
PA-0310	CPV FAIRVIEW ENERGY CENTER	PA	9/2/2016	Dew point heater 3.2	3.2	MMBtu/hr		0.080	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Clean fuel and good combustion practices	0.035	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.080	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-12
EMERGENCY DIESEL GENERATORS (1341-5864-P) AND FIRE WATER PUMP ENGINE (1341-5865-P), PERMIT DATES 5/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0264	WPSC - WEST MARINETTE	WI	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices, only fire pipeline quality natural gas	0.080	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	GOOD COMBUSTION PRACTICES	0.021	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.037	LB/MMBTU
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	heater	3	MMBTU/H		0.040	LB/MMBTU
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	fuel gas heater	18	MMBTU/H		0.054	LB/MMBTU
MD-0041	CPV ST. CHARLES	MD	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	GOOD COMBUSTION PRACTICES	0.080	LB/MMBTU
TX-0693	ANTELOPE ELK ENERGY CENTER	TX	4/22/2014	heater	5.5	MMBTU/H		0.080	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	dew point heater	13.32	mmBtu/hr		0.041	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.083	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.050	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	0.111	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.090	LB/MMBTU
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Gas heater	0		Good combustion practice.	0.084	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion	0.110	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.037	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-29
EMERGENCY DIESEL GENERATORS (1341 HP AND LARGER) AND FIRE WATER PUMP ENGINES FROM 5/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Only combust pipeline quality natural gas, operate and maintain process according to manufacturer's recommendations.	0.0050	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Only combust pipeline quality natural gas and operate and maintain according to manufacturer's recommendations.	0.0050	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0054	LB/MMBTU
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.0026	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	good combustion practices, operator training, and proper emissions unit design, construction and maintenance.	0.0057	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Good combustion controls	0.0082	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Good combustion controls.	0.0079	LB/MMBTU
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	good combustion practices		
FL-0364	SEMINOLE GENERATING STATION	FL	3/21/2018	Two natural gas heaters (<10 MMBtu/hr each)	9.9	MMBtu/hr		0.0050	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0056	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0081	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Good combustion pratices	0.0053	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0055	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0054	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.0050	LB/MMBTU
MD-0041	CPV ST. CHARLES	MD	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	EXCLUSIVE USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0050	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-19

EMERGENCY DIESEL GENERATORS (1341 TO 1864 HP) AND FIRE WATER PUMP ENGINES (300 TO 600 HP), PERMIT DATES 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	DEW POINT HEATER	5	MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.0050	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Fuel Preheater	8.5	MMBTU/H		0.0500	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	0.0081	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.0500	LB/MMBTU
NY-0104	CPV VALLEY ENERGY CENTER	NY	8/1/2013	Gas heater	0		Good combustion practice.		LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0080	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.0060	LB/MMBTU

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Table E-24

EMERGENCY DIESEL GENERATORS (1364-5864 hp) AND FIRE WATER PUMPS (300-500 hp), PERMIT DATES 1/01/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Operate and maintain heaters according to manufacturer's recommendations. Only combust pipeline quality natural gas.	0.01	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Operate and maintain heater according to the manufacturer's recommendations and only combust pipeline quality natural gas.	0.01	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	0.0075	LB/MMBTU
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	0.0075	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.005	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	WI	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices and only fire pipeline quality natural gas	0.008	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.007	LB/MMBTU
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	dew point heater	13.32	mmBtu/hr		0.008	LB/MMBTU
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	PA	4/1/2013	DEW POINT HEATER	15	MMBTU/H		0.008	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

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Table E-29

EMERGENCY DIESEL GENERATORS (1341 TO 1864 HP) AND FIRE WATER PUMP ENGINES (300 TO 600 HP), PERMIT DATES 1/1/2013 THROUGH 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Operate and maintain according to manufacturer's recommendations. Only combust pipeline quality natural gas.	0.0100	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Operate and maintain heater according to the manufacturer's recommendations and only combust pipeline quality natural gas.	0.0100	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.0037	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12-month rolling average.	0.0076	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low sulfur fuel	0.0072	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low sulfur fuel	0.0079	LB/MMBTU
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	0.0070	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0074	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0075	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Fuel Heater	15	mmbtu/hr		0.0070	LB/MMBTU
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Low sulfur/carbon fuel and good combustion practices	0.0070	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	WI	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices and use pipeline quality natural gas	0.0080	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU

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Table E-19

EMERGENCY DIESEL GENERATORS (1,341 TO 1,864 HP) AND FIRE WATER PUMP ENGINES (300 TO 600 HP), PERMIT DATES 1/01/2010 THROUGH 12/31/2012 8/30/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.0070	LB/MMBTU
MD-0041	CPV ST. CHARLES	MD	4/23/2014	FUEL GAS HEATER	9.5	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0070	LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	DEW POINT HEATER	5	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	0.0075	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.0090	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0070	LB/MMBTU

DO NOT DISCLOSE per O.C.G.A. §§ 50-18-72(a)(34) and 40 CFR Part 2.

Table E-10
EMERGENCY DIESEL GENERATORS (1,384 TO 1,864 HP) AND FIRE WATER PUMP ENGINES (500-5,000 HP), PERMIT DATES 1/1/2013 THROUGH 8/30/2023
LISTINGS FOR STRINGENT PM2.5 LIMITS (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Operate and maintain heater according to manufacturer's recommendations. Only combust pipeline quality natural gas.	0.0100	LB/MMBTU
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Operate and maintain heater according to the manufacturer's recommendations and only combust pipeline quality natural gas.	0.0100	LB/MMBTU
WI-0299	WPL- RIVERSIDE ENERGY CENTER	WI	8/20/2020	Natural Gas-Fired Space and Unit Heater (P30)	15.5	MMBTU/H	Only combust natural gas in each heater.	0.0075	LB/MMBTU
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Good combustion practices	0.0037	LB/MMBTU
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12-month rolling average.	0.0095	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Low sulfur fuel	0.0072	LB/MMBTU
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Low sulfur fuel	0.0079	LB/MMBTU
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	0.0070	LB/MMBTU
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Combustion control	0.0050	LB/MMBTU
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Good combustion practices.	0.0074	LB/MMBTU
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	0.0075	LB/MMBTU
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Fuel Heater	15	mmbtu/hr		0.0070	LB/MMBTU
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	KS	3/31/2016	Indirect fuel-gas heater	2	mmBTU/hr		0.0075	LB/MMBTU
WI-0264	WPSC - WEST MARINETTE	WI	2/15/2016	Natural gas-fired pipeline heater (process P14)	3.5	mmBtu/hr	Good combustion practices, only fire pipeline quality natural gas	0.0080	LB/MMBTU
MD-0045	MATTAWOMAN ENERGY CENTER	MD	11/13/2015	FUEL GAS HEATER	13.8	MMBTU/H	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			0.0070	LB/MMBTU

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RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0694	INDECK WHARTON ENERGY CENTER	TX	2/2/2015	heater	3	MMBTU/H			LB/MMBTU
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	5/20/2014	fuel gas heater	18	MMBTU/H			LB/MMBTU
MD-0042	WILDCAT POINT GENERATION FACILITY	MD	4/8/2014	DEW POINT HEATER	5	MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion pracitces.	0.0075	LB/MMBTU
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	0.0090	LB/MMBTU
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.0070	LB/MMBTU

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TABLE E-27
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 9/29/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AL-0329	COLBERT COMBUSTION TURBINE PLANT	AL	9/21/2021	Three Gas Heaters	10	MMBtu/hr		5128.98	TPY
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P04)	10	MMBTU/H	Low-NOx burners, only combust pipeline quality natural gas, and operate and maintain heater according to manufacturer's recommendations.		
WI-0300	NEMADJI TRAIL ENERGY CENTER	WI	9/1/2020	Natural Gas-Fired Heater (P05)	10	MMBTU/H	Low-NOx burners, only combust pipeline quality natural gas, and operate and maintain according to manufacturer's recommendations.		
MI-0445	INDECK NILES, LLC	MI	11/26/2019	FGFUELHTR (2 fuel pre-heaters)	27	MMBTU/H	Energy Efficiency Measures and the use of a low carbon fuel (pipeline quality natural gas)	13848	TPY
VA-0332	CHICKAHOMINY POWER LLC	VA	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	use of natural gas and high efficiency design and operation	6261	TPY
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Fuel Heater	13	mmBtu/hour	Good combustion practice	6700	TPY
IL-0129	CPV THREE RIVERS ENERGY CENTER	IL	7/30/2018	Fuel Heater	12.8	mmBtu/hr	Good combustion practice	6600	TPY
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR1: Natural gas fired fuel heater	20.8	MMBTU/H	Natural gas fuel	6310	TPY
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	MI	7/16/2018	EUFUELHTR2: Natural gas fired fuel heater	3.8	MMBTU/H	Natural gas fuel	6310	TPY
VA-0328	C4GT, LLC	VA	4/26/2018	Dew Point Heater	140	MMCF/YR	use of natural gas and high efficiency design and operation	8208	TPY
OH-0374	GUERNSEY POWER STATION LLC	OH	10/23/2017	Fuel Gas Heaters (2 identical, P007 and P008)	15	MMBTU/H	Natural gas, low-emitting fuel	7695	TPY
TX-0824	JACKSON COUNTY GENERATING FACILITY	TX	6/30/2017	Natural-Gas-Fired Fuel Gas Heaters	15.9	MMBTU/HR	natural gas as a low carbon fuel, good operating and maintenance practices, efficient design, and low annual capacity	2818.74	TPY
MI-0423	INDECK NILES, LLC	MI	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27	MMBTU/H	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).	13848	TPY
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/5/2016	EUFUELHTR (Fuel pre-heater)	3.7	MMBTU/H	Good combustion practices.	1934	TPY
IL-0121	INVENERGY NELSON EXPANSION LLC	IL	9/27/2016	Fuel Heater	15	mmbtu/hr		1836	TPY
VA-0325	GREENSVILLE POWER STATION	VA	6/17/2016	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	185	MMBTU/HR	Natural gas and fuel and high efficiency design and operation.		
PA-0311	MOXIE FREEDOM GENERATION PLANT	PA	9/1/2015	Fuel Gas Heater	0			7845	TPY

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TABLE E-27
FUEL HEATERS AT POWER STATIONS, PERMIT DATES FROM 1/01/2013 THROUGH 9/29/2023
LISTINGS FOR GREENHOUSE GASES (AS CO2e)

RBLC ID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
TX-0758	ECTOR COUNTY ENERGY CENTER	TX	8/1/2014	Dew-Point Heater	9	MMBTU/H		2631	TPY
TX-0749	GOLDEN SPREAD ELECTRIC COOPERATIVE, ANTELOPE STATION	TX	6/2/2014	Fuel Gas Heater	5.5	MMBtu/hr (HHV)		1488	TPY
TX-0757	INDECK WHARTON ENERGY CENTER	TX	5/12/2014	Pipeline Heater	3	MMBtu/hr (HHV)		624.78	TPY
IA-0107	MARSHALLTOWN GENERATING STATION	IA	4/14/2014	dew point heater	13.32	mmBtu/hr		6860	TPY
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	PA	12/17/2013	Fuel Preheater	8.5	MMBTU/H		4996.3	TPY
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	MI	12/4/2013	Fuel pre-heater (EUFUELHTR)	3.7	MMBTU/H	Good combustion practices	1934	TPY
MI-0406	RENAISSANCE POWER LLC	MI	11/1/2013	EU-HEATERSC: Natural gas-fired fuel heater used for heating natural gas prior to combustion in the CTGs. Misc. boilers, furnaces, and heaters	20	MMBTU/H	Good combustion practices	10943	TPY
MI-0410	THETFORD GENERATING STATION	MI	7/25/2013	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12	MMBTU/H heat input each fuel heater	Efficient combustion; energy efficiency.	6156	TPY

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Appendix F

BACT Cost Tables

Table 1 Potential CO_2 Emissions from the Proposed CT Units

Emission Factor[1] (lb/MMBtu)	Total Potential Heat Input[2] (MMBtu/hr)	Capacity Factor	Total Potential Emissions (tpy CO_2)
118.85	11,952	41.5%	**2,582,166**

1. From 40 CFR Part 75, Appendix G, Eq. G-4
2. Total Heat Input Capacity includes (based on ISO conditions without use of evaporative cooling):
   Turbine No. 8 3,984 MMBtu/hr
   Turbine No. 9 3,984 MMBtu/hr
   Turbine No. 10 3,984 MMBtu/hr
3. Emissions (tpy) = $\frac{\text{EF (lb/MMBtu)} * \text{Total Heat Input Capacity (MMBtu/hr)} * \text{Operating Duration (hr/yr)}}{\text{2,000 lbs}}$

Table 2 Assumptions Used in CCS Cost Estimation

Parameters	Value	Unit
Pipeline Length[1]	280	mi
Pipeline Diameter[2]	12	in
Pump Booster Stations[2]	7	
Number of Primary and Backup Injection Wells[3]	6	
Number of Pressure Monitoring Wells[3]	4	
Number of Ground Water Monitoring Wells (deep and shallow)[3]	15	
Uncontrolled Annual CO_2 Emissions[4]	2,582,166	tpy
Control Efficiency[5]	90	%
Annual Captured CO_2 Emissions	2,323,949	tpy

1. Distance from the facility to the nearest potential CO2 sequestration facility (Baldwin County, AL) based on Southern Company experience and knowledge of geologic characterization in the southeast US.
2. Determined using the FE/NETL CO_2 Transport Cost Model (Excel spreadsheet) as detailed in *FECM/NETL CO2 Transport Cost Model (2023): Description and User's Manual (DOE/NETL-2023/4385)*. The model was used to determine the optimal pipeline diameter and number of booster pump stations, based on projected CO_2 capture rates, to produce the minimum expected cost of CO_2 transport.
3. Estimates were based on previous site characterization completed in Mobile County, AL (adjacent to Baldwin County) through DOE's Southeastern Regional Carbon Sequestration Program (RCSP). It was assumed development and operating costs for Baldwin County, AL would be similar, since geology is comparable.
4. Potential CO_2 emissions calculated in Table 1.
5. 90% CCS Control Efficiency assumed based on BSER for baseload units in proposed Subpart TTTTa.

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Table 3 Total Costs for Carbon Capture

Estimated Annual Captured CO		2,323,949	tpy captured
Cost of CO_2 Capture from Recent NGCC Post Combustion Capture Studies[2]	Without 45Q PTC	With 45Q PTC	
Cost and Performance Baseline for Fossil Energy Plants Volume 1, National Energy Technology laboratory, NETL-2023/4320 (October 2022)[3]	$113	$45	$/ton CO_2 captured
Natural Gas Combined Cycle Power Plants with Post Combustion CCS (3002016289), Electric Power Research Institute (August 2020)[3]	$133	$65	$/ton CO_2 captured
Levelized Annual Costs of CO_2 Capture using average $/ton from public studies[4]	$285,727,800	$127,764,500	
Annual capital adder associated with higher flue gas volume and temperature.[5]	$40,000,000	$40,000,000	
Levelized Annual Total Costs for CO_2 Capture	$325,727,800	$167,764,500	annual additional cost to ratepayers for CO_2 capture
Relative Cost of CO_2 Capture[6]	$140	$72	$/ton CO_2 captured

1. Estimated captured CO_2 from Table 2
2. $ / ton CO_2 captured for each study was calculated using the increase in levelized cost of electricity (LCOE) in $/MWh between the non-capture and capture cost estimates divided by the CO2 capture rate (tons/MWh) of the capture case on a constant MWh basis. The LCOE consists of capital, O&M, and fuel components. Total overnight capital costs (MM$) were converted to levelized annual capital costs ($/MWh) using the annual MWh output and a fixed charge rate (FCR) that accounts for the weighted average cost of capital (WACC) and depreciation using the NETL method described in *Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance* (February 2021). Annual O&M costs were escalated and levelized using an assumed 2.2% escalation rate and the after-tax WACC (ATWACC). Annual fuel costs were levelized using the 2023 Annual Energy Outlook (AEO) fuel price forecast and the WACC as described in the *NETL Quality Guidelines*.
3. The LCOE and $/ton CO_2 captured published in these studies were adjusted from the study year $ basis to 2026 $ using an assumed escalation rate of 2.2%. They were also adjusted from 85% capacity factor to a 41.5% capacity factor, consistent with the proposed CT units, and from a 30-yr project life of turbines to a 45-year life of the proposed turbines. The ATWACC for the EPRI study was 8%, while the NETL study used 6.54% (nominal). The effective tax rate was assumed to be 25.7%. All adjustment calculations followed the method outlined in the *NETL Quality Guidelines* referenced above.
4. Levelized Annual Costs of CO_2 Capture using average $/ton from public studies ($/yr) = Estimated Annual Captured CO_2 (tpy) x Average $/ton
5. The total additional CO_2 capture capital associated with higher flue gas volume and temperature from the proposed CT units compared to a combined cycle is much greater than $40 MM. The average public study $/ton figure is based on the capital requirements and CO_2 captured from 2 H-class combustion turbines. The CO2 captured from the 3 CT's in the proposed project is over double the amount of CO_2 from the combined cycle. Therefore, the capital estimate derived by multiplying $/ton by the project's CO_2 tons/yr is also over double the cost of the combined cycle. In addition, the amount of flue gas produced by the simple cycle CT's is almost triple that of the combined cycles while the additional cooling load for the flue gas is over 10 times that of the combined cycles. The combination of all these additional capital requirements results in an additional $40 MM capital cost being needed over and above what the public study $/ton metric predicts.
6. Relative Cost of CO_2 Capture($/ton) = $\frac{\text{Levelized Annual Total Costs of } CO_2 \text{ Capture ($/yr)}}{\text{Estimated Annual Captured } CO_2 \text{ (tpy)}}$

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Table 4 Capital and O&M Costs for CO_2 Transportation and Storage

Transportation and Storage Capital Costs			
Pipeline Costs[1]			**2026 Dollars**
Pipeline Materials			$68,745,600
Pipeline Labor			$203,078,740
Pipeline Right of Way			$19,488,350
Pipeline Miscellaneous			$69,910,100
Surge Tank			$1,832,250
Pipeline Control System			$164,730
Pipeline Booster Pumps (7)			$22,853,620
		Total Pipeline Capital	$386,073,390
Storage Costs[2]	**Number**	**Unit Cost, $MM**	**2026 Dollars**
Primary Injection Wells	4	$6.1	$24,222,500
Backup Injection Wells	2	$6.1	$12,111,300
Pressure Monitoring Wells	4	$4.9	$19,564,400
Groundwater Monitoring Wells	5 Deep / 10 shallow	$0.23 / $0.03	$1,455,700
Distribution Lines & Pumps	1 / 2	$11.7 / $1.2	$13,974,500
Characterization, Permitting, Seismic and Microseismic Monitoring	Various	Various	$10,539,100
Total Storage Capital			$81,867,500
		Total Capital + 15% Contingency (TOC)	$538,132,000
		Fixed Charge Rate (FCR) used to levelize annual costs based on TOC (7.7% ATWACC, 15-year depreciation schedule, 45-year operating period)[3]	0.0909
		Levelized Annual Transportation and Storage Capital Costs (TOC x FCR)[5]	$48,916,200
Transportation and Storage O&M Costs			
Levelized Annual Transportation O&M[1,4]			$19,309,360
Levelized Annual Storage O&M[2,4]			$6,545,800
Relative Cost of CO_2 Transportation and Storage ($/ton CO_2 Captured)			$32

1. CO2 Transportation Capital and O&M values (2026 $) were developed using the FE/NETL CO2 Transport Cost Model (Excel spreadsheet) as detailed in *FECM/NETL CO2 Transport Cost Model (2023): Description and User's Manual (DOE/NETL-2023/4385)*. The model determined the optimal pipeline diameter and number of booster pump stations to produce the minimum expected cost of CO2 transport. The cost methodology is detailed in the User's Manual. The ATWACC used in the Transport Cost Model was 7.7%, referenced in Lazard's *Levelized Cost of Energy Analysis—Version 16.0 (2023)* as the mid-point ATWACC for utilities.
2. Storage Capital and O&M estimates (2026 $) were based on previous site characterization completed in Mobile County, AL (adjacent to Baldwin County) through DOE's Southeastern Regional Carbon Sequestration Program (RCSP). It was assumed development and operating costs for Baldwin County, AL would be similar, as geology is similar. The Mobile County site was fully characterized and has been previously permitted with CO_2 injection and subsurface monitoring that was recently closed out from a pilot carbon capture unit at the site that captured CO_2 at a rate of 500 tpd.
3. FCR determined using the NETL method described in *Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance* (February 2021). The ATWACC used to calculate the FCR was 7.7%, referenced in Lazard's *Levelized Cost of Energy Analysis—Version 16.0 (2023)* as the mid-point ATWACC for utilities.
4. Transportation and Storage O&M costs were levelized by escalating costs in 2026 $ annually throughout the operating period to determine the NPV of each using the 7.7% discount factor from Lazard. The levelized cost is the constant annual payment needed to equal the NPV assuming the same discount factor. The operating period for transportation is 45 years, while the operating period for storage includes 45 years operating and 50 years of post-injection site monitoring per the maximum requirements of a CO2 storage permit.
5. Relative Cost of CO_2 Transport and Storage ($/ton) = $\frac{\text{Levelized Annual T\&S Capital Costs (\$ MM/yr) + Levelized Annual T\&S O\&M Costs (\$ MM/yr)}}{\text{Estimated Annual Captured } CO_2 \text{ (tpy)}}$

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Table 5 Overall Cost of CCS

	Without 45Q PTC	With 45Q PTC
Levelized Annual Total Costs for CO_2 Capture[1]	$325,512,240	168,116,540
Levelized Annual Transportation and Storage Capital Costs[2]	$48,916,200	
Levelized Annual Transportation O&M Costs[2]	$19,309,360	
Levelized Annual CO_2 Storage O&M Costs[2]	$6,545,800	
Total Annual CCS Costs	**00,283,600**	**242,887,900**
Relative Cost of CCS ($/ton CO_2 Captured)	**$172**	**$105**

1. From Table 3
2. From Table 4
3. Relative Cost of CO2 Capture($/ton) = $\frac{\text{Total Annual CCS Costs ($/yr)}}{\text{Estimated Annual Captured } CO_2 \text{ (tpy)}}$

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STF-PIA-10-9 Attachment

Appendix G

Air Dispersion Modeling Files

STF-PIA-10-9 Attachment

Appendix H

FLM AQRV Waiver

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Connors, Jeffrey

From: Ghazal Majidi-Weese - FS, Asheville - FS, NC <ghazal.majidi-weese@usda.gov>
Sent: Monday, November 20, 2023 4:55 PM
To: Connors, Jeffrey
Cc: Kim, Byeong; Allison, Steve; Bandzul, Jonathan E.; Shepherd, Lorinda; Bae, Estelle
Subject: RE: Class I AQRV Waiver Request (PSD Permit Application FLM Notification – Georgia Power Company - GA)

November 20, 2023

Dear Jeffrey:

Thank you for sending the information regarding the Georgia Power Company - Plant Yates proposed project near the City of Newnan, Coweta County, GA. Based on the emission rates and distances from the Class I areas listed below, the United States Department of Agriculture (USDA) anticipates that modeling would not show any significant additional impacts to Air Quality Related Values (AQRV) at the Class I areas administered by the USDA Forest Service. Therefore, we are not requesting that any Class I AQRV analyses be included in the PSD permit application. Our screening of this analysis does not indicate agreement with any AQRV analysis protocols or conclusions applicants may make independent of Federal Land Manager review. Please note that we are specifically addressing the need for an AQRV analysis for Class I areas managed by the USDA Forest Service.

Class I Area	Distance to Facility (km)	Annual Emissions (tpy [1])
Cohutta Wilderness	156	1544
Sipsey Wilderness	221	1544
Joyce Kilmer-Slickrock Wilderness	225	1544
Shining Rock Wilderness	283	1544

1. Sulfur dioxide, nitrogen oxides, total fine particulate matter (PM, PM_{10}, and $PM_{2.5}$), and sulfuric acid mist.

The state and/or EPA may have a different opinion regarding the need for a Class I increment analysis. Should the emissions or the nature of the project change significantly, please contact myself, Gisele Majidi-Weese (ghazal.majidi-weese@usda.gov, 828-337-2323) of the USDA Forest Service so that we might re-evaluate the project proposal.

Thank you for keeping us informed and involving the USDA Forest Service in the project review.

Regards,
Gisele

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Gisele Majidi-Weese, PE (s□e□□er)
Air Resource Specialist
Environmental Engineer

Forest Service
Southern Region

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ghazal.majidi-weese@usda.gov

Remote from As□e□ille, NC
□□□.fs.fed.□s

Caring for the land and serving people

From: Connors, Jeffrey <Jeffrey.Connors@aecom.com>
Sent: Friday, November 10, 2023 9:33 AM
To: Ghazal Majidi-Weese - FS, Asheville - FS, NC <ghazal.majidi-weese@usda.gov>
Cc: Kim, Byeong <Byeong.Kim@dnr.ga.gov>; Allison, Steve <Steve.Allison2@dnr.ga.gov>; Bandzul, Jonathan E. <jbandzul@southernco.com>
Subject: Class I AQRV Waiver Request

Good Morning Gisele,

On October 23, 2023, Georgia Power Company (GPC) filed with the Georgia Public Service Commission (PSC) an update to its Integrated Resource Plan (IRP) that sets forth a flexible, comprehensive plan to support the Georgia's extraordinary economic growth and continue providing clean, safe, reliable, and affordable power for customers. As part of this plan, GPC is proposing to construct and operate up to 1,400 MW from three advanced class, dual-fuel simple-cycle combustion turbine units (the proposed CT units) at Plant Yates (Coweta County, GA) to complement energy storage systems in support of continued integration of renewable sources and provide peaking power when needed. As peaking (non-baseload) units, operation of each proposed CT unit will be limited to a capacity factor less than its design efficiency for purposes of compliance with 40 CFR 60, Subpart TTTT. Each proposed CT unit will exclusively use clean fuels, such as natural gas and ultra-low sulfur diesel (ULSD), and will be equipped with dilution selective catalytic reduction (dSCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. Additionally, the proposed project will include ancillary supporting equipment such as an emergency generator, emergency fire water pump engine, and fuel gas heaters.

The proposed project is located approximately 156 km from the Cohutta Wilderness Area. There are several other Class I areas within 300 km of Plant Yates including:

- Sipsey Wilderness: 221 km;
- Joyce Kilmer – Slickrock Wilderness Area: 225 km;
- Great Smoky Mountains National Park: 250 km; and
- Shining Rock Wilderness Area: 283 km.

The FLAG 2010 guidance states that a proposed source with a Q/d ratio less than 10 will likely not have an adverse impact on air quality related values (AQRVs), where 'Q' is the annual steady-state equivalent emission rate based on the sum of NO_X, SO_2, PM_{10}, and H_2SO_4 emissions (in tons per year, based on maximum 24-hour emissions) and 'd' is the distance (km) to the closest Class I area. Since the proposed CT units will be fueled by pipeline quality natural gas, or ultra-low sulfur diesel (ULSD) when gas is not available, the project has a 'Q' value for each fuel. As an initial screening tool, the Q/d ratio is used to determine whether a proposed source may affect AQRVs of Class I areas and warrants

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further analysis. Please note that for purposes of this project, all SO_2 emissions are assumed to form H_2SO_4 prior to release, so no SO_2 emissions are included in the Q/d calculation for this project.

For natural gas, 'Q' is 746.4 tons per year based on the following calculation: 41.0 lb/hr (NO_X) + 7.0 lb/hr (PM_{10}, filterable) + 8.8 lb/hr (H_2SO_4) = 56.8 lbs/hr/CT x 3 CTs = 170.4 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 746.4 tons/year. Relative to the Cohutta Wilderness Area, Q = 746.4 tons/year, d=156, and Q/d ratio = 4.8.

For ULSD, 'Q' is 1,544.0 tons per year based on the following calculation: 74.0 lb/hr (NO_X) + 35.4 lb/hr (PM_{10}, filterable) + 8.1 lb/hr (H_2SO_4) = 117.5 lbs/hr/CT x 3 CTs = 352.5 lbs/hr x 8,760 hrs/yr ÷ 2000 lbs/ton = 1,544.0 tons/year. Relative to the Cohutta Wilderness Area, Q = 1,544.0 tons/year, d=156, and Q/d ratio = 9.9.

The Q/d for natural gas is 4.8 and the Q/d for ULSD is 9.9, slightly over the screening threshold. However, given that ULSD is intended to be used only when gas is not available, GPC asks that you find that refined analysis is not warranted.

Attached please find a completed Southern Region US Forest Service "Request for Determination of Need for a Class I AQRV Modeling Analysis" form that provides all the relevant information to make a determination regarding this project. It would be greatly appreciated if you could provide a response within the next two weeks so that your determination may be included in the air permit application.

Thank you for considering our request and we look forward to your response. If you have any questions, please contact me.

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Request for Applicability of Class I Area Modeling Analysis
Southern Region, U.S. Forest Service

Facility Name (Company Name)	Georgia Power Company Yates Steam-Electric Generating Plant
New Facility or Modification?	Modification (new emission units at an existing major stationary source)
Source Type/BART Applicability	Peaking power generation
Project Location (County/State/ Lat. & Long. in decimal degrees)	Coweta County, Georgia. 33.46N, 84.90W

Application Contacts

Applicant		***Consultant***		***Air Agency Permit Engineer***	
Company	Georgia Power Company	Company	AECOM	Agency	Georgia Environmental Protection Division
Contact	Jon Bandzul	Contact	Jeffrey Connors	Contact	Steve Allison
Address	241 Ralph McGill Blvd., BIN 10221, Atlanta, Georgia 30308	Address	250 Apollo Drive Chelmsford, MA 01824	Address	2 Martin Luther King Jr. Drive SE Suite 1456, East Tower Atlanta, GA 03033
Phone #	(404) 851-7056	Phone #	(978) 905-2166	Phone #	(470) 938-3360
Email	jbandzul@southernco.com	Email	jeffrey.connors@aecom.com	Email	Steve.Allison2@dnr.ga.gov

Briefly Describe the Proposed Project

Georgia Power Company (GPC) is proposing to construct and operate up to 1,400 MW from three advanced class, dual-fuel simple-cycle combustion turbine units (the proposed CT units) at Plant Yates (Coweta County, GA) to complement energy storage systems in support of continued integration of renewable sources and to provide peaking power when needed. As peaking (non-baseload) units, operation of each proposed CT will be limited to a capacity factor less than its design efficiency for purposes of compliance with 40 CFR 60, Subpart TTTT. Each proposed CT unit will exclusively use clean fuels, such as natural gas and ultra-low sulfur diesel (ULSD), and will be equipped with dilution selective catalytic reduction (dSCR) to minimize nitrogen oxide (NO_X) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. Additionally, the proposed project will include ancillary supporting equipment such as an emergency generator and emergency fire water pump engine.

The proposed project constitutes a major modification at a major stationary source. As such, GPC will apply to the Georgia Environmental Protection Division (EPD) for an air permit authorizing construction of the project. Based on preliminary information, the proposed project will be subject to PSD permitting for emissions of NO_X, PM, PM_{10}, $PM_{2.5}$, CO, VOC, H_2SO_4, and GHG.

Proposed Emissions and BACT

Criteria Pollutant	***Emissions***		***Emission Factor (AP-42, Stack Test, Other?)***	***Proposed BACT***
	Maximum hourly (lb/hr/CT)	***CT Proposed Annual [(1)(2] (tons/yr)***		
Nitrogen Oxides	(Gas = 41.0 lb/hr) (ULSD = 74.0 lb/hr)	(Gas = 293.0 tons/yr) (ULSD = 470.8 tons/yr)	Vendor Design	Dilution selective catalytic reduction system (dSCR)
Sulfur Dioxide	(Gas = 5.7 lb/hr) (ULSD = 5.3 lb/hr)	(Gas = 30.7 tons/yr) (ULSD = 26.3 tons/yr)	Mass Balance	N/A (for purposes of condensable PM emissions, all SO_2 is assumed to form H_2SO_4 prior to release due to the presence of dSCR and oxidation catalysts for NO_X, CO, and VOC control)
Particulate Matter (Filterable Only)	(Gas = 7.0 lb/hr) (ULSD = 35.4 lb/hr)	(Gas = 37.9 tons/yr) (ULSD = 176.55 tons/yr)	Vendor Design	Clean fuels, as defined in 40 CFR 60, Subpart TTTT

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Sulfuric Acid Mist	(Gas = 8.8 lb/hr) (ULSD = 8.1 lb/hr)	(Gas = 46.96 tons/yr) (ULSD = 40.3 tons/yr)	Mass Balance	Clean fuels, as defined in 40 CFR 60, Subpart TTTT
Proximity to U.S. Forest Service Class I Areas				
Class I Area	Cohutta Wilderness		Sipsey Wilderness	Joyce Kilmer – Slickrock Wilderness
Distance from Facility (km)	156		221	225

(1) *Annual* emissions are based on operation of the proposed CT units at baseload rating and limited to a capacity factor less than their design efficiency for purposes of compliance with 40 CFR 60, Subpart TTTT.

(2) While all SO_2 is assumed to form H_2SO_4 prior to release, the above listed SO_2 emissions will still be included in the permit application to be consistent with reporting obligations under the Acid Rain Program (ARP) and Cross-State Air Pollution Rule (CSAPR) SO_2 Group 2 trading program.

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