Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

March 2024

Facility Name: Yates Steam-Electric Generating Plant
City: Newnan
County: Coweta
AIRS Number: 04-13- 077-00001
Application Number: TV-802465
Date Application Received: December 8, 2023

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Yates Steam-Electric Generating Plant (Plant Yates) referred to as "The Plant" for a permit to construct three (3) advanced class, dual-fuel simple-cycle combustion turbine (CT) units at Plant Yates, located in Coweta County, Georgia. The proposed project will include construction of the proposed CT units and 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 1,400 MW of capacity. If gas is unavailable, the proposed CT units will run on distillate oil and provide approximately 1,000 MW of capacity. Each proposed CT unit will be equipped with a dilution selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions.

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include three (3) advanced class, dual-fuel simple-cycle combustion turbine (CT) units, an emergency generator, an emergency fire water pump engine, and three fuel gas heaters.

The modification of the Plant due to this project will result in an emissions increase in particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), lead (Pb), and sulfuric acid mist (H_2SO_4). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), and sulfuric acid mist (H_2SO_4) emissions increases were above the PSD significant level threshold.

The Plant is located in Coweta County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC).

The EPD review of the data submitted by the Plant related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an

aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), and sulfuric acid mist (H_2SO_4), as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to the Plant for the modifications necessary to construct three (3) advanced class, dual-fuel simple-cycle combustion turbine (CT) units at Plant Yates. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On December 8, 2023, Yates Steam-Electric Generating Plant (hereafter "The Plant") submitted an application for an air quality permit to construct the proposed CT units and will include installation of new associated equipment, such as an emergency generator, an emergency fire water pump engine, and three fuel gas heaters. The facility is located at 708 Dyer Rd in Newnan, Coweta County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Y	✓		
PM_{10}	Y	✓		
$PM_{2.5}$	Y	✓		
SO_2	Y			✓
VOC	Y	✓		
NO_x	Y	✓		
CO	Y	✓		
TRS	N/A			✓
H_2S	N/A			✓
Individual HAP	Y	✓		
Total HAPs	Y	✓		
Total GHGs	Y	✓		

Table 1-2 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

Table 1-2: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-077-0001-V-05-0	October 06, 2023	Title V Renewal
4911-077-0001-V-05-1	Draft Permit	Align the schedule for the biennial compliance report required by 40 CFR 63 Subpart DDDDD

PSD Applicability Analysis

The proposed modification to the Plant involves the construction and operation of new emission units. A project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases – a significant emissions increase and a significant net emissions increase. A significant emissions increase of a regulated NSR pollutant for construction of a new emissions unit is projected to occur if the sum of the difference between the potential to emit (as defined in 40 CFR Part 52.21(b)(4)) from each new emissions unit following completion of the project and

the baseline actual emissions of these units before the project equals or exceeds the significant amount for that pollutant (as defined in 40 CFR Part 52.21(b)(23)).
Table 3-6 of the application 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 of the application and the potential to emit for associated equipment presented in Table 3-5 of the application. Table 3-7 of the application provides the annual HAP potential to emit.

Emissions of regulated NSR pollutants are based, in part on the following combustion turbine scenarios: (1) operating limits based on a capacity factor of 41.5% for ultra-low fuel oil combustion or natural gas combustion per CT, including startup and shutdown; (2) 300 startup/shutdown events per year; (3) sulfur content limit of natural gas is 0.5 grains per 100 standard cubic feet; and (4) sulfur content limit of fuel oil is 15 ppm. Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1-3 below.

Emissions of regulated NSR pollutants are based, in part on the following operating parameters for the auxiliary equipment as follows; (1) 8,760 hrs/yr of natural gas combustion per heater (3 heaters total); (2) 200 hrs/yr of ultra-low fuel oil combustion for the emergency generator; (3) 500 hrs/yr of ultra-low fuel oil combustion for the emergency fire-water pump; and (4) 272,338,900 gal/yr of annual throughput for the Turbine Fuel Diesel Storage Tank based on all 3 CTs operating on oil at max heat input rate for permitted capacity factor.

As shown in Table 1-3, 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 of the application for details).

Table 1-3: Emissions Increases from the Project

Pollutant	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
[1]PM	252	25	Yes
[1]$PM_{2.5}$	318	10	Yes
[1]PM_{10}	318	15	Yes
VOC	1,046	40	Yes
NO_X	511	40	Yes
CO	3,025	100	Yes
SO_2	31	40	No
Pb	0.26	0.6	No
[2]CO_2e	3,075,978	75,000	Yes
SAM	47	7	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.

The emissions calculations for Table 1-3 can be found in detail in the facility’s PSD application (see Appendix C of Application No. TV-802465). These calculations have been reviewed and approved by the Division.

Based on the information presented in Table 1-3 above, The Plant’s proposed modification, as specified per Georgia Air Quality Application No. TV-802465, is classified as a major modification under PSD because the potential emissions of PM, PM_{10}, $PM_{2.5}$, NOx, CO, CO_2e, VOC, and SAM exceed the PSD significant emissions rate thresholds. The net emissions increase for the project is equivalent to the potential emissions from the project as there are no contemporaneous projects to be considered in the net emissions increase analysis.

Through its new source review procedure, EPD has evaluated the Plant's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. TV-802465, the Plant has proposed 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) simple-cycle CTs, with a capacity of 1,000 MW-1,400 MW combined, based on whether it is firing natural gas or ultra-low sulfur distillate oil (ULSD).

Associated equipment associated with the Project includes:

- One (1) ULSD fuel-fired emergency generator with an output capacity of 3,250 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.

Combustion Turbines

The proposed CT units will provide between 1,000 to 1,400 MW of capacity, combined, 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.

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.

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.

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 feet in diameter and equipped with a submerged fill system to reduce evaporative VOC emissions during filling operations.

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.

The Plant permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at https://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) – Visible Emissions
Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. Visible emissions testing may be required at the discretion of the Director.

The combustion turbines at the Plant are subject to this regulation. The turbines will fire pipeline-quality natural gas with emissions exhibiting minimal opacity. The turbines will also combust ULSD fuel oil, and it is anticipated that the firing of these clean fuels in conjunction with proper operation ensures compliance with this rule.

Georgia Rule 391-3-1-.02(2)(d) – Fuel-Burning Equipment
Rule (d) limits the PM emissions, visible emissions, and NOx emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. As defined in 391-3-1-.01(cc), fuel burning equipment is:

> *"Fuel-burning equipment" means 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 combustion turbines are used for the generation of electric power, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment and are not subject to the requirements of Rule (d). However, the fuel gas heaters will be used for the production of thermal energy and will be subject to Rule (d).

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide
Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to all "fuel-burning sources" and not just "fuel-burning equipment" this rule applies to the combustion turbines, emergency generator, firewater pump engines, and the gas heaters.

For fuel-burning sources below 100 MMBtu/hr , the fuel sulfur content is limited to 2.5% sulfur by weight.

Rule 391-3-1-.02(2)(g)1 applies to each combustion turbine because each has an individual heat input capacity exceeding 250 MMBtu/hr and was constructed after January 1, 1972. Sulfur dioxide emissions from each combustion turbine shall not exceed 0.8 lb/MMBtu of heat input derived from liquid fossil fuel in accordance with Rule 391-3-1-.02(2)(g)1(i). The fuel sulfur content limit for fuels burned in each combustion turbine is 3 percent sulfur by weight in accordance with Rule 391-3-1-.02(2)(g)2, which applies to each piece of equipment rated at 100 MMBtu/hr or greater regardless of fuel type. The proposed permit will require that the facility only fire distillate fuel oil with a 0.0015% sulfur content and natural gas, thus limiting fuel sulfur content to well below 3% sulfur. This limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK.

Georgia Rule 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. The Plant will employ appropriate control methods and take precautions to limit fugitive dust emissions from the project so as not to exceed 20% opacity.

Georgia Rule 391-3-1-.02(2)(bb) – Petroleum Liquid Storage

Rule (bb) establishes requirements for storage tanks with a capacity greater than 40,000 gallons storing a petroleum liquid with a true vapor pressure greater than 1.52 pounds per square inch absolute (psia). As the ULSD has a true vapor pressure less than 1.52 psia, the new fuel oil storage tank is not subject to the requirements of Rule (bb).

Georgia Rule 391-3-1-.02(2)(nn) – VOC Emissions from External Floating Roof Tanks

Rule (nn) establishes requirements for external floating roof tanks storing petroleum liquids with a capacity greater than 40,000 gallons. As the proposed fuel oil storage tank is a fixed roof tank and not an external floating roof tank, Rule (nn) will not apply.

Georgia Rule 391-3-1-.02(2)(uu) – Visibility Protection

Rule (uu) requires EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The nearest Class I area to Plant Yates is Cohutta Wilderness, which is approximately 150 kilometers north-northeast of the Project site. The visibility-impacting pollutants include NOx, PM_{10}, SO_2, and H_2SO_4. A screening analysis of federal Class I areas resulted in a Q/d value less than 10. Therefore, a full review of the anticipated impact on visibility was not performed. Further documentation regarding an evaluation of impacts related to these projects on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, was provided in Section 9 of Application No. TV-802465.

Georgia Rule 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).

Georgia Rule 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. The Plant 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.

Georgia Rule 391-3-1-.02(2)(mmm) – NOx Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity

Rule (mmm) establishes ozone season NOx 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."*

Georgia Rule 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% oxygen 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.

Georgia Rule 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 of the application, 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.

Georgia Rule 391-3-1-.03(1) – Construction (SIP) Permitting

The proposed project will require physical construction activities to complete the proposed modifications. Potential emissions associated with the proposed project to install the combustion turbine units, fuel gas heaters, emergency generator, and fire water pump are above the de minimis construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i). Further, as discussed in Section 4.2 of the application, PSD permitting is required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix A of the application.

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

The Plant 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. The application requested a significant modification with construction (PSD) to the Plant's Title V permit and contained copies of the electronic attachments to the GEOS application submitted for the Project in Appendix A of the application.

Georgia Rules 391-3-1-.02(12), (13), and (14) – Cross State Air Pollution Rules (Annual NO_X, Annual SO_2, and Ozone Season NO_X)

These regulations incorporate the Cross State Air Pollution Rule (CSAPR) requirements into the Georgia Rules for Air Quality Control. The regulations provide allocations for Georgia for 2017 and thereafter.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed permit in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, considering energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards

The federal NSPS regulations are codified at 40 CFR Part 60. NSPS apply to new or modified "affected facilities" as defined in specific subparts of 40 CFR Part 60. Georgia EPD has been delegated the authority to administer the federal NSPS and has adopted by reference, unless otherwise noted, the NSPS standards. *See* Air Quality Control Rule 391-3-1- 02(8). Additional discussion of NSPS applicability is presented below.

40 CFR Part 60, Subpart A – General Provisions

Subpart A contains the general provisions of the NSPS regulations. Specifically, the provisions of Subpart A apply to the owner or operator of any stationary source that contains an affected facility, construction or modification of which is commenced after the date of publication of the standard and is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to Part 60. General requirements may include notifications, monitoring, recordkeeping and/or performance testing of specific sources.

40 CFR Part 60, Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The requirements of NSPS Subpart Kb apply to storage vessels which have a storage capacity greater than 19,813 gallons (75 cubic meters (m^3)) that store Volatile Organic Liquids (VOL) for which construction, modification, or reconstruction commenced after July 23, 1984. However, per 40 CFR 60.110b(b), NSPS Kb does not apply to storage vessels with a storage capacity greater than 39,890 gallons (151 cubic meters (m^3)) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa)(0.5 psia). The proposed fuel oil storage tank at the facility will have a storage capacity of 5.72 million gallons and will store ultra-low sulfur diesel (ULSD). The maximum true vapor pressure of the ULSD stored in the fuel oil storage tank is far less than the 3.5 kPa (~0.01 psia typ.) threshold; therefore, the requirements of NSPS Kb do not apply.

40 CFR Part 60, 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. The Plant 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. The Plant 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.

40 CFR 60, 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.

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, or 96 ppm, corrected to 15% O_2, when firing either fuel and operating at less than 75% load, based on a 4-hour rolling average.

As discussed in the BACT analysis in Section 4.0, 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.

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.

The Plant 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.

40 CFR 60 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. The Plant 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)).

40 CFR 60 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 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 April 2024. The Plant will evaluate the rule when it is finalized to determine how best to comply.

Non-Applicability of All Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPS, besides Subpart A, are categorically not applicable to the proposed project.

National Emissions Standards For Hazardous Air Pollutants

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

The Plant 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 the Plant demonstrates that Plant Yates is an area source of HAP emissions and will remain so after the Project. The Plant 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.

40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP in 40 CFR 63, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

40 CFR 63 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 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 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.

40 CFR 63 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The Combustion Turbine MACT standard 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.

40 CFR 63 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).

Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The applicability of a particular NESHAP to the proposed project can be readily ascertained based on the industrial source category covered. All other NESHAP are categorically not applicable to the proposed projects.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the combustion turbines associated with the proposed project would most likely result from a malfunction of the associated control equipment. The Plant cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

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 of the application.

For NO_X, the Plant 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, the Plant 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.

40 CFR 68 – Risk Management Plan

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

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.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, VOC, CO, sulfuric acid mist (H_2SO4), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).

Combustion Turbines (Source Codes: CT8 - CT10) BACT Review

Combustion Turbines (Source Codes: CT8 - CT10) - Background

The Plant is in Newnan in Coweta County, Georgia. The present permitted facility consists of two steam electric generating units (Emission Unit IDs SG06 and SG07) with oxidation catalysts and a water bath heater unit (Emission Unit ID WBH1) that all burn natural gas. The key elements of the proposed project include:

- Combustion Turbine Units 8, 9, and 10 (Emission Unit IDs CT8, CT9, and CT10) to provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized. The simple-cycle CT units will fire natural gas or ULSD fuel and have DLN combustors and water injection for NOx emissions control. The emission control technologies for the proposed CT units also 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.
- 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.

Combustion Turbines (Source Codes: CT8 - CT10) – NOx Emissions

Applicant's Proposal

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on NOx emissions from each combustion turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for NOx.

NOx Formation – Combustion Turbines

There are five (5) primary pathways of NOx production from turbine combustion processes: thermal NOx, prompt NOx, NOx from N_2O intermediate reactions, fuel NOx, and NOx formed through reburning. The three most important mechanisms are thermal NOx, prompt NOx, and fuel

NOx.[1] For natural gas-fired units, most NOx is derived from thermal NOx. Distillate oils also have low levels of fuel-bound nitrogen (N_2) that contribute to NOx formation.

NO_X emissions from the 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.[2]

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.

Identification of NO_X Control Technologies – Combustion Turbines (Step 1)

EPA's control technology database was searched, relevant existing and proposed federal and state emissions standards were considered, recently issued new source review permits and associated applications were reviewed, if available, for similar sources, and 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 were conducted.

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 of the application. Control technology determinations not included in the RBLC

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

[2] For example, see NSPS Subpart GG, 40 CFR 60.332(a)(1) through (4).

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 the Plant 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).[3] Each is discussed in the following sections.

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.[4] 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.[5]

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

[3] 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 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.

[4] 42 Fed. Reg. 53782, 53785 (Oct. 3, 1977).

[5] 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.

temperature and residence time. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + ½O_2 = 2N_2 + CO_2 + 2\ H_2O \qquad (1)$$
$$4\ NH_3 + 6NO = 5N_2 + 6\ H_2O \qquad (2)$$

Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls.[6] 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.[7] 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

2

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:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad (1)$$
$$6\ NO + 4\ NH_3 \rightarrow 5\ N_2 + 6\ H_2O \qquad (2)$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \qquad (3)$$
$$6\ NO + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O \qquad (4)$$
$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O \qquad (5)$$

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.

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

[7] *Id.*

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.

Elimination of Technically Infeasible NO_X Control Options – Combustion Turbines (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

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. The Plant 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. The Plant 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 the Plant 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 those located at Canal Generating Station Unit 3.

Summary and Ranking of Remaining NO_X Controls – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent NO_X Controls – Combustion Turbines (Step 4)

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.

Selection of Emission Limits for NO_X BACT (Step 5)

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.[8] 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, The Plant 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,

[8]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.

- 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.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 15 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.

EPD Review – Combustion Turbines NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[9]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM_{10}, CO, Greenhouse Gases, H_2SO_4 and VOC BACT analyses.

After reviewing the RBLC Database and other research methods, EPD contacted the regulating agencies directly, to verify, if SCR technology has been successfully installed on Large-Frame Simple Cycle Combustion Turbines. The Division agrees that Large-Frame Simple Cycle Combustion Turbines are defined as having a rating of 25 MW or Greater. Aeroderivative Turbines are not considered to be Large Frame Combustion Turbines. The RBLC data was examined for the last ten years for simple cycle combustion turbines.

[9] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Conclusion – Combustion Turbines NOx Control

The technically feasible control technologies for NOx emission control for simple cycle turbines are SCR, DLN burners and water injection. Therefore, the combination of SCR, DLN combustors and water injection are the demonstrated and technically feasible options to be considered for this project.

The only facilities with simple cycle combustion turbines that have installed an SCR in the RBLC database are;

- Bayonne Energy Center, 2,143,980 MMBtu/hr, Natural Gas, 2.5 ppmvd
- Perryman Generating Station, 120 MW, (2), 60 MW each, Ultra Low Sulfur Diesel (ULSD), 5 ppmvd

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 be in commercial operation in the US.

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of the use of SCR, ULSD, dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation for NOx control in the combustion turbines.

The Division agrees with the proposed limits for normal operation. **To account for emissions due to startup, shutdown or malfunction, the Division has decided to include the facility requested limit of 168.3 tons of NOx emissions (12 consecutive month average) firing natural gas or fuel oi**l from each of the combustion turbines (Source Codes: CT8-CT10).

The BACT selection for the Combustion Turbines (Source Codes: CT8-CT10) is summarized below in Table 4-1:

Table 4-1: BACT Summary for the Combustion Turbines (Source Codes: CT8-CT10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Dry Low NOx Burners (firing Natural Gas) Water Injection (firing Fuel Oil) Clean Fuels SCR	2.5 ppmvd @ 15% O_2 5 ppmvd @ 15% O_2	4 hours	NOx CEMS

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Dry Low NOx Burners (firing Natural Gas) Water Injection (firing Fuel Oil) Clean Fuels SCR	168.3 tons*	12 consecutive month average	NOx CEMS

*Limit includes emissions during startup and shutdown.

Combustion Turbines (Source Codes: CT8 - CT10) – CO Emissions

Applicant's Proposal

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for CO emissions from each combustion turbine. The following sections details the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for CO.

CO Formation – Combustion Turbines

CO from combustion turbines is a by-product of incomplete combustion. Conditions leading in incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion-temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to ensure NO_X emissions remain low may result in increased CO emissions.

Identification of CO Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

EPA's control technology database was searched, relevant existing and proposed federal and state emissions standards were considered, recently issued new source review permits and associated applications, if available, for similar sources were reviewed, and 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 were conducted.

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 of the application. 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.

Elimination of Technically Infeasible CO Control Options – Combustion Turbines (Step 2)

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.

Summary and Ranking of Remaining CO Controls – Combustion Turbines (Step 3)

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

Evaluation of Most Stringent CO Controls – Combustion Turbines (Step 4)

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.

Selection of Emission Limits for CO BACT (Step 5)

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, the Plant 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 15 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, the Plant 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.

<u>EPD Review – CO Combustion Turbines Control</u>

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period and with a focus of finding similar control technologies in use, at the facility, as possible. The Division has prepared a CO BACT comparison spreadsheet for the similar units using the resources, as discussed in the NOx BACT review.

GA EPD agrees that an oxidation catalyst, pipeline quality natural gas and ULSD fuel represents BACT control technology for CO. The draft permit restricts CO emissions to 1,004.6 tons during any 12 consecutive months, 3.5 ppmvd (NG) and 5.0 ppmvd (FO).

<u>Conclusion – CO Combustion Turbines Control</u>

The technically feasible control technologies for CO emission control for simple cycle turbines are an oxidation catalyst, clean fuels, and good combustion practices. Therefore, the combination of an oxidation catalyst, clean fuels, and good combustion practices are the demonstrated and technically feasible options to be considered for this project.

The only facilities with simple cycle combustion turbines that have installed an oxidation catalyst in the RBLC database are;

- Tennessee Valley Authority (TVA) – Johnsonville Combustion Turbine Plant, 465.8 MMBtu/hr, Natural Gas, 5 ppmvd (except startup/shutdown)
- Bayonne Energy Center, 2,143,980 MMBtu/hr, Natural Gas, 5.0 ppmvd, 7.21 lb/h avg of 3, 1 hour stack test
- Pueblo Airport Generating Station, 799.7 MMBtu/hr, Natural Gas, 55 lb/h 1-hour avg (SU&SD)
- Troutdale Energy Center, LLC, 653 MW, NG or Ultra Low Sulfur Diesel (ULSD), 6 ppmvd, 3 1-hour avg

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 be in commercial operation in the US.

The limits for the other facilities evaluated above are either above or consistent with the facility's proposed limits and the Division agrees with the facility's proposed limits. The Division agrees with the proposed BACT control technology of the use of an oxidation catalyst, ULSD, and good combustion practices.

The Division agrees with the proposed limits for normal operation. **To account for emissions due to startup, shutdown or malfunction, the Division has decided to include the facility requested limit of 1004.6 tons of CO emissions (12 consecutive month average) firing natural gas or fuel oi**l from each of the combustion turbines (Source Codes: CT8-CT10).

The BACT selection for the combustion turbines (Source Codes CT8-CT10) is summarized below in Table 4-2:

Table 4-2: BACT Summary for the Combustion Turbines (Source Codes CT8-CT10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices Clean Fuels Oxidation Catalyst	3.5 ppmvd @ 15% O_2 (NG) 5.0 ppmvd @ 15% O_2 (FO)	4 hours	CO CEMS
CO	Good Combustion Practices Clean Fuels Oxidation Catalyst	1004.6 tons*	12 consecutive month average	CO CEMS

Combustion Turbines (Source Codes: CT8 - CT10) – VOC Emissions

Applicant's Proposal

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for VOC emissions from each combustion turbine. The following sections details the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for VOC.

VOC Formation – Combustion Turbines

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

Identification of VOC Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

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 of the application.

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.

Elimination of Technically Infeasible VOC Control Options – Combustion Turbines (Step 2)

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.

Summary and Ranking of Remaining VOC Controls – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent VOC Controls – Combustion Turbines (Step 4)

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.

Selection of Emission Limits for VOC BACT (Step 5)

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.[10] 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, the Plant 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.

[10] 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.

The Plant 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 McDonough, compliance with the VOC BACT emission limits for the proposed CT units will be assured as long as CO emissions comply with the corresponding CO BACT emission limits.

EPD Review – Combustion Turbines (Source Codes CT8-CT10) VOC Control

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period, and facilities that had modified the existing process. The Division has prepared a VOC BACT comparison spreadsheet for the similar units using the resources, as discussed in the NOx BACT review.

GA EPD agrees that an oxidation catalyst, good combustion practices, pipeline quality natural gas and ULSD fuel represents BACT control technology for VOC.

Of a total of 25 Facility VOC BACT limits, 10 facilities (40 %) had the 2.0 ppm limit for natural gas despite being new or existing units, therefore this limit is a common choice for the VOC BACT limit for natural gas.

Conclusion – Combustion Turbines (Source Codes CT8-CT10) VOC Control

The technically feasible control technologies for VOC emission control for simple cycle turbines are an oxidation catalyst, clean fuels and good combustion practices. Therefore, the combination of an oxidation catalyst, clean fuels, and good combustion practices are the demonstrated and technically feasible options to be considered for this project.

The only facilities with simple cycle combustion turbines that have installed an oxidation catalyst in the RBLC database are;

- Nacero Penwell Facility, Natural Gas, 1.7 ppmvd (except startup/shutdown)
- Bayonne Energy Center, 2,143,980 MMBtu/hr, Natural Gas, 2.0 ppmvd, 1.65.21 lb/h avg of 3, 1 hour stack test every 5 years

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 be in commercial operation in the US. 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.

The limits for the other facilities evaluated above are similar to the facility's proposed limits and the Division agrees with the facility's limits. The Division agrees with the proposed BACT control technology of the use of an oxidation catalyst, ULSD, and good combustion practices.

The BACT selection for the Combustion Turbines (Source Codes CT8-CT10) is summarized below in Table 4-3:

Table 4-3: BACT Summary for the Combustion Turbines (Source Codes CT8-CT10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Practices Clean Fuels Oxidation Catalyst	2.0 ppmvd @ 15% O_2 (NG) 2.0 ppmvd @ 15% O_2 (FO)		3-run stack test EPA Reference Method 25A

Combustion Turbines (Source Codes: CT8-CT10) – Particulate Matter, Particulate Matter Less than 10 Microns (PM_{10}), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions

Applicant's Proposal

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on particulate related emissions from each simple-cycle turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits selected as BACT for filterable PM and total PM_{10}/$PM_{2.5}$.

PM Formation – Combustion Turbines

PM emissions from the proposed CT units include both filterable and condensable particles.[11] 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.

Identification of PM Control Technologies – Combustion Turbines (Step 1)

EPA's control technology database was searched and relevant existing and proposed federal and state emissions standards to identify potentially available control options for PM emissions from the proposed CT units were considered. The results of these RBLC searches are summarized in Appendix E, Tables E-7 through E-12 of the application. 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 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.[12] Accordingly, only the use of cleans fuels and good combustion practices are considered further.

[11] 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.

[12] 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

Elimination of Technically Infeasible PM Control Options – Combustion Turbines (Step 2)

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

Summary and Ranking of Remaining PM Controls – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent PM Controls – Combustion Turbines (Step 4)

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.

Selection of Emission Limits for PM BACT (Step 5)

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

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.

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

EPD Review – Particulate Matter, Particulate Matter Less than 10 Microns (PM_{10}), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period. The Division has prepared a PM/PM_{10}/$PM_{2.5}$ BACT comparison spreadsheet for the similar units using the above-mentioned resources.

GA EPD agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for PM/PM_{10}/ $PM_{2.5}$.

Conclusion – Combustion Turbines (Source Codes CT8-CT10) Particulate Matter, Particulate Matter Less than 10 Microns (PM_{10}), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Control

The only facilities in the RBLC database which were comparable to the Plant are:

- The Doswell Energy Center Facility which is comparable to the facility since it has two 1,961 MMBTU/hr GE7FA combustion turbines. The PM limit chosen for BACT is 24.5 lb/hr (0.006 lb/MMBTU) for natural gas, the same as the facility's proposed BACT limit of 24.5 lb/hr (0.006 lb/MMBTU) natural gas.

- The Nacogdoches Power Electric Generating Plant which is comparable to the facility since it has a 232 MW GE7FA combustion turbine and has a 24.5 lb/hr (0.006 lb/MMBTU) NG limit (less than the performance guarantee).

- Hill County Generating Facility which is comparable to the facility since it has a 171 MW combustion turbine and 24.3 lb/hr (0.007 lb/MMBTU) FO limit (lower than the facility's proposed limit of 48.5 lb/hr (0.014 lb/MMBTU).

Most of the RBLC database BACT limits were for different combustion turbine type, and size, therefore the limits were not comparable for the facility's combustion turbines.

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 be in commercial operation in the US. Total PM emissions from Canal Generating Station Unit 3 when firing natural gas are limited to either 0.0073 lb/MMBtu or 0.012 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 lb/MMBtu when firing distillate.

The BACT selection for the Combustion Turbines (Source Codes CT8-CT10) is summarized below in Table 4-4:

Table 4-4: BACT Summary for the Combustion Turbines (Source Codes CT8-CT10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Clean Fuels	0.006 lb/MMBTU, or 24.5 lb/hr (NG) 0.014 lb/MMBTU, or 48.5 lb/hr (FO)		3-run stack test EPA Reference Methods 5, 17, 201A, and/or 202, as applicable

Combustion Turbines (Source Codes: CT8-CT10) – Sulfuric Acid Mist (SAM) Emissions

Applicant's Proposal

SAM Formation – Combustion Turbines

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.

Identification of SAM Control Technologies – Combustion Turbines (Step 1)

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).

Elimination of Technically Infeasible SAM Control Options – Combustion Turbines (Step 2)

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

Summary and Ranking of Remaining SAM Controls – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent SAM Controls – Combustion Turbines (Step 4)

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.

Selection of Emission Limits for SAM BACT (Step 5)

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 the use of clean fuels with inherently low sulfur content. The Plant 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.

EPD Review – Combustion Turbines SAM Control

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period. The Division has prepared a SAM BACT comparison spreadsheet for the similar units using the above-mentioned resources.

GA EPD agrees that pipeline quality natural gas with 0.5 grains sulfur/ 100 standard cubic feet, and ULSD fuel represents BACT control technology for SAM. This is to be verified by supplier documentation.

Conclusion – Combustion Turbines SAM Control

The only facilities in the RBLC database which were comparable to the Plant are:

- The Neches Station which is comparable to the facility since it has four 232 MW simple cycle combustion turbines. The SAM limit chosen for BACT is 1.0 grains sulfur/100 standard cubic feet for natural gas, twice the limit of the facility’s proposed BACT limit of 0.5 grains sulfur/100 standard cubic feet natural gas.

- Gaines County Power Plant which is comparable to the facility since it has four 227.5 MW simple cycle combustion turbines. The SAM limit chosen for BACT is 1.54 grains sulfur/100 standard cubic feet for natural gas, three times the limit of the facility’s proposed BACT limit of 0.5 grains sulfur/100 standard cubic feet natural gas.

- Lauderdale Plant which is comparable to the facility since it has five 200 MW simple cycle combustion turbines. The SAM limit chosen for BACT is 2 grains sulfur/100 standard cubic feet for natural gas, four times the limit of the facility's proposed BACT limit of 0.5 grains sulfur/100 standard cubic feet natural gas.

Most of the RBLC database BACT limits were for different combustion turbine types, and size, therefore the limits were not comparable for the facility's combustion turbines.

The BACT selection for the Combustion Turbines is summarized below in Table 4-5:

Table 4-5: BACT Summary for the Combustion Turbines

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SAM	Clean Fuels	0.5 grains sulfur/100 standard cubic feet (NG) ULSD (15 ppm sulfur) (FO)		Fuel Supplier Documentation

<u>Combustion Turbines (Source Codes: CT8-CT10) – Greenhouse Gases – CO_2 Emissions</u>

<u>Applicant's Proposal</u>

This section contains a high-level review of pollutant formation and possible control technologies for the combustion turbine systems. Though the primary GHG emissions from natural gas and fuel oil combustion in the combustion turbine systems are CO_2, GHG BACT is discussed separately for CH_4 and N_2O.

CO_2 production from combustion occurs in theory by a reaction between carbon in any fuel and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[13] CH_4 can be emitted when natural gas and fuel oil are not burned

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

completely in combustion.[14] The last primary component for calculating greenhouse gas emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete gas and oil combustion situations, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[15]

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of BACT for CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2).

Greenhouse Gases – CO_2 Formation – Combustion Turbines

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.

Identification of Greenhouse Gases – CO_2 Control Technologies – Combustion Turbines (Step 1)

The applicant 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 of the application. 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.

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[14] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998. Chapter 1, Section 3, *Fuel Oil Combustion*. July 1998.

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

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 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]

[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.").

[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).

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-line 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 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. The Plant has nonetheless evaluated technical feasibility and other factors for this control option.

[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.

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.

<u>Elimination of Technically Infeasible Greenhouse Gases – CO_2 Control Technologies – Combustion Turbines (Step 2)</u>

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

Use of clean fuels with inherently low sulfur content are 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

[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.

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 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.

[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.

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

<u>Summary and Ranking of Remaining Greenhouse Gases – CO_2 Control Technologies – Combustion Turbines (Step 3)</u>

[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.").

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.

Evaluation of Most Stringent Greenhouse Gases – CO_2 Control Technologies – Combustion Turbines (Step 4)

Carbon Capture and Sequestration

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 of the application 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.

[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 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, the Plant 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 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] 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 the 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.

[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.

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 of the application, 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.

[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.")

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 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 considering 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.

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[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.

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.

Selection of BACT for Greenhouse Gases – CO_2 Combustion Turbines (Step 5)

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, The Plant 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 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.

EPD Review – Combustion Turbines Greenhouse Gases – CO_2 Control

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period. The Division has prepared a GHG BACT comparison spreadsheet for the similar units using the above-mentioned resources.

GA EPD agrees that clean fuels, efficient design, and good combustion, operating, and maintenance practices represents BACT control technology for greenhouse gases (GHG).

Conclusion – Combustion Turbines Greenhouse Gases – CO_2 Control

The only facilities in the RBLC database which were comparable to the Plant are:

- The LBWL Station which is comparable to the facility since it has a 667 MMBTU/hr simple cycle combustion turbine. The CO_2 limit chosen for BACT is 318,404 tons/yr 12 month rolling limit, a third of the limit of the facility's proposed BACT limit of 1,024,630 tons/yr 12 month rolling limit GHGs, yet the facility's proposed combustion turbines are much larger at 4,084 MMBTU/hr maximum natural gas, 3,984 MMBTU/hr maximum ULSD.

- Calcasieu Pass LNG Project which is comparable to the facility since it has three 927 MMBTU/hr simple cycle combustion turbines. The GHG limit chosen for BACT is 1,426,146 tons/yr 12 month rolling limit GHGs for all three combustion turbines, similar to the limit of the facility's proposed BACT limit of 1,024,630 tons/yr 12 month rolling limit GHGs for all three combustion turbines.

- Pueblo Airport Generating Station which is comparable to the facility since it has three 375 MMBTU/hr simple cycle combustion turbine. The CO_2 limit chosen for BACT is 193,555 tons/yr 12 per rolling 365-day average, 19 percent of the limit of the facility's proposed BACT limit of 1,024,630 tons/yr 12 month rolling limit GHGs, yet the facility's proposed combustion turbines are much larger at 4,084 MMBTU/hr maximum natural gas, 3,984 MMBTU/hr maximum ULSD.

Most of the RBLC database BACT limits were for different combustion turbine types, and size, therefore the limits were not comparable for the facility's combustion turbines.

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 be in commercial operation in the US. Those units did not identify any add-on controls for BACT.

The BACT selection for the Combustion Turbines is summarized below in Table 4-6:

Table 4-6: BACT Summary for the Combustion Turbines Greenhouse Gases – GHG Control

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Good Combustion and Operating Practices, and Low Sulfur Fuels	14,483,434 MMBtu/hr, 1,024,830 tpy CO_2e 12-month rolling total	monthly	CEMS, 12 month rolling average

Combustion Turbines (Source Codes: CT8-CT10) – Greenhouse Gases – CH_4 Emissions

Applicant's Proposal

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 was provided for CH_4 emissions from the proposed CT units.

Greenhouse Gases – CH_4 Emissions Formation – Combustion Turbines

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

Identification of Greenhouse Gases – CH_4 Control Technologies – Combustion Turbines (Step 1)

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.

Elimination of Technically Infeasible Greenhouse Gases – CH_4 Control Technologies – Combustion Turbines (Step 2)

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

Summary and Ranking of Remaining Greenhouse Gases – CH_4 Control Technologies – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent Greenhouse Gases – CH_4 Control Technologies – Combustion Turbines (Step 4)

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.

Selection of BACT for Greenhouse Gases – CH_4 Combustion Turbines (Step 5)

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).

EPD Review – Combustion Turbines Greenhouse Gases – CH_4 Control

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

Conclusion – Combustion Turbines Greenhouse Gases – CH_4 Control

Refer to the previous review for GHGs.

Combustion Turbines (Source Codes: CT8-CT10) – Greenhouse Gases – N_2O Emissions

Applicant's Proposal

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 was provided for N_2O emissions from the proposed CT units.

Greenhouse Gases – N_2O Emissions Formation – Combustion Turbines

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.

Identification of Greenhouse Gases – N_2O Control Technologies – Combustion Turbines (Step 1)

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.

[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

Elimination of Technically Infeasible Greenhouse Gases – N_2O Control Technologies – Combustion Turbines (Step 2)

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.

Summary and Ranking of Remaining Greenhouse Gases – N_2O Control Technologies – Combustion Turbines (Step 3)

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.

Evaluation of Most Stringent Greenhouse Gases – N_2O Control Technologies – Combustion Turbines (Step 4)

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.

Selection of BACT for Greenhouse Gases – N_2O Combustion Turbines (Step 5)

Good combustion practices are selected as BACT for N_2O emissions from the proposed CT units. The Plant 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).

EPD Review – Combustion Turbines Greenhouse Gases – N_2O Control

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.

Conclusion – Combustion Turbines Greenhouse Gases – N_2O Control

Refer to the previous review for GHGs.

[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

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine BACT Review

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine Background

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).

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 after-treatment-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. After-treatment-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).

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine – NOx Emissions

Applicant's Proposal

NOx Formation – Engines

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.

Identification of NO_X Control Technologies – Engines (Step 1)

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 of the application, 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.

Elimination of Technically Infeasible NO_X Control Options – Engines (Step 2)

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.

Summary and Ranking of Remaining NO_X Controls – Engines (Step 3)

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.

[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.

Evaluation of Most Stringent NO_X Controls – Engines (Step 4)

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.

Selection of Emission Limits for NO_X BACT (Step 5)

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 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.

EPD Review – Engines NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[43]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM_{10}, CO, Greenhouse Gases, H_2SO_4 and VOC BACT analyses.

Conclusion – Engines NOx Control

The technically feasible control technologies for NOx emission control for engines are compliance with NSPS IIII standards.

[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.

[43] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

The only facilities that state meeting the requirements of NSPS IIII standards as BACT for the engines of comparable size in the RBLC database are 37% of the emergency generator entries and 50% for the firewater pump entries, some for example are;

- Cronus Chemicals, 3,985 hp, 6.4 g/kwh (4.8 g/hp-hr): 360 hp, 4 g/kw-hr (3 g/bhp)
- Nucor Steel, 3,000 hp, 4.8 g/hp-hr
- Nucor Steel Arkansas, 3,634 hp, 5.6 g/kw-hr
- Midwest Fertilizer Company, 3,600 hp, 4.42 g/hp-hr
- Lincoln Land Energy Center, 320 hp, 4 g/kw-hr
- MEC North. LLC and MEC South LLC, 300 hp, 3 g/bhp

The limits for the other facilities evaluated above are consistent with the proposed BACT determination of compliance with NSPS Subpart IIII and the Division agrees with the proposed BACT control technology of the use of an engine that is designed to meet NSPS Subpart IIII requirements.

The Division agrees with the proposed limits for normal operation. The emergency generator will also have a limit of 200 hours/yr, including 100 hrs/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations. The firewater pump is limited to 500 hours/yr.

The BACT selection for the Engines is summarized below in Table 4-7:

Table 4-7: BACT Summary for the Engines

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx, CO, VOC, PM	Tier 2 Engine (EG1) and Tier 3 Engine (FWP1)	NSPS Subpart IIII standards	NA	Comply with NSPS Subpart IIII

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine – CO Emissions

Applicant’s Proposal

CO Formation – Engines

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.

Identification of CO Control Technologies – Engines (Step 1)

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 of the application, 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).[44]

Elimination of Technically Infeasible CO Control Options – Engines (Step 2)

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.

Summary and Ranking of Remaining CO Controls – Engines (Step 3)

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.

Evaluation of Most Stringent CO Controls – Engines (Step 4)

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.[45] 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.[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 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.

Selection of Emission Limits for CO BACT (Step 5)

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

[44] 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.

[45] 70 Fed. Reg. 39874 (July 11, 2005).

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

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.

EPD Review – Engines CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[47]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Engines CO Control

The technically feasible control technologies for CO emission control for engines are compliance with NSPS Subpart IIII standards.

The only facilities that state meeting the requirements of NSPS Subpart IIII standards as BACT for the engines of comparable size in the RBLC database are 55% of the emergency generator entries and 42% for the firewater pump entries, some for example are;

- Cronus Chemicals, 3,985 hp, 3.5 g/kwh (2.6 g/hp-hr): 369 hp, 3.5 g/kw-hr
- Belle River Combined Cycle Plant, 399 hp, 3.5 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- LBLW Erickson Station, 6,000 hp, 3.5 g/kw-hr
- Lincoln Land Energy Center, 320 hp, 3.5 g/kw-hr
- MEC North. LLC and MEC South LLC, 300 hp, 2.6 g/bhp

The limits for the other facilities evaluated above are consistent with the proposed BACT determination of compliance with NSPS Subpart IIII and the Division agrees with the proposed BACT control technology of the use of an engine that is designed to meet NSPS Subpart IIII requirements.

The Division agrees with the proposed limits for normal operation. The emergency generator will also have a limit of 200 hours/yr, including 100 hours/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations. The firewater pump will be limited to 500 hours/yr.

The BACT selection for the Engines is summarized above in Table 4-7.

[47] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine – VOC Emissions

Applicant's Proposal

VOC Formation – Engines

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.

Identification of VOC Control Technologies – Engines (Step 1)

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 of the application, 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.

Elimination of Technically Infeasible VOC Control Options – Engines (Step 2)

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.

Summary and Ranking of Remaining VOC Controls – Engines (Step 3)

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.

Evaluation of Most Stringent VOC Controls – Engines (Step 4)

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.[48] 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

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

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.

Selection of Emission Limits for VOC BACT (Step 5)

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.

EPD Review – Engines VOC Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the VOC BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[49]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Engines VOC Control

The technically feasible control technologies for VOC emission control for engines are compliance with NSPS Subpart IIII standards.

The only facilities that state meeting the requirements of NSPS Subpart IIII standards as BACT for the engines of comparable size in the RBLC database are 22% of the emergency generator entries and for the firewater pump entries they were very varied, some for example are;

- Cronus Chemicals, 3,985 hp, 6.4 g/kwh (4.8 g/hp-hr): 369 hp, 4 g/kw-hr
- Riverview Energy Corporation, 2,800 hp, 6.4 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- Magnolia Power Generating Station, 2,937 hp, 4.8 g/hp-hr

[49] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

The limits for the other facilities evaluated above are consistent with the proposed BACT determination of compliance with NSPS Subpart IIII and the Division agrees with the proposed BACT control technology of the use of an engine that is designed to meet NSPS Subpart IIII requirements.

The Division agrees with the proposed limits for normal operation. The emergency generator will also have a limit of 200 hours/yr, including 100 hours/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations. The firewater pump will be limited to 500 hours/yr.

The BACT selection for the Engines is summarized above in Table 4-7.

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine – PM Emissions

Applicant's Proposal

PM Formation – Engines

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.

Identification of PM Control Technologies – Engines (Step 1)

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 of the application, Table E-18, there were no cases in which Tier 4 was identified as BACT for PM. The Plant has nonetheless evaluated technical feasibility and other factors for this control option.

Elimination of Technically Infeasible PM Control Options – Engines (Step 2)

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.

Summary and Ranking of Remaining PM Controls – Engines (Step 3)

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.

Evaluation of Most Stringent PM Controls – Engines (Step 4)

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 ratings.[50] 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.

Selection of Emission Limits for PM BACT (Step 5)

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.

EPD Review – Engines PM Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[51]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Engines PM Control

The technically feasible control technologies for PM emission control for engines are compliance with NSPS Subpart IIII standards.

The only facilities that state meeting the requirements of NSPS Subpart IIII standards as BACT for the engines of comparable size in the RBLC database are 42% of the emergency generator entries and 45% for the firewater pump entries, some for example are;

[50] 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.

[51] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

- Cronus Chemicals, 3,985 hp, 0.2 g/kwh (0.15 g/hp-hr): 369 hp, 0.2 g/kw-hr
- Belle River Combined Cycle Plant, 399 hp, 0.2 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 0.2 g/kw-hr
- LBLW Erickson Station, 4,474 ke, 0.2 g/kw-hr
- Lincoln Land Energy Center, 1,250 kw, 0.2 g/kw-hr
- MEC North. LLC and MEC South LLC, 1,341 hp, 0.2 g/kw-hr

The limits for the other facilities evaluated above are consistent with the proposed BACT determination of compliance with NSPS Subpart IIII and the Division agrees with the proposed BACT control technology of the use of an engine that is designed to meet NSPS Subpart IIII requirements.

The Division agrees with the proposed limits for normal operation. The emergency generator will also have a limit of 200 hours/yr, including 100 hrs/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations. The firewater pump will be limited to 500 hours/yr.

The BACT selection for the Engines is summarized above in Table 4-7.

Emergency Generator (EG1) and Fire Water Pump (FWP1) Engine – GHG Emissions

Applicant's Proposal

GHG Formation – Engines

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.

Identification of GHG Control Technologies – Engines (Step 1)

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 of the application, 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.[52] 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.

Elimination of Technically Infeasible GHG Control Options – Engines (Step 2)

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.

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

Summary and Ranking of Remaining GHG Controls – Engines (Step 3)

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.

Evaluation of Most Stringent GHG Controls – Engines (Step 4)

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.

Selection of Emission Limits for GHG BACT (Step 5)

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.

EPD Review – Engines GHG Control

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period. The Division has prepared a GHG BACT comparison spreadsheet for the similar units using the above-mentioned resources.

GA EPD agrees that clean fuels, efficient design, and good combustion, operating, and maintenance practices represents BACT control technology for greenhouse gases (GHG).

Conclusion – Engines GHG Control

The only facilities in the RBLC database which were comparable to the Plant are:

- The LBWL Station which is comparable to the facility since it has a 4,474.20 kw/hr emergency generator. The CO_2 limit chosen for BACT is 590 tons/yr 12 month rolling limit and the use of ULSD.

- Cronus Chemicals which is comparable to the facility since it has a 369 hp firewater pump. The GHG limit chosen for BACT is a 25 tpy limit and a 100 hrs/yr operational limit.

- Nucor Steel Arkansas which is comparable to the facility since it has one 3,634 hp emergency generator. The CO_2 limit chosen for BACT is 163 lb/MMBtu.

The limits for the other facilities evaluated above are consistent with the proposed BACT determination of compliance with NSPS Subpart IIII, a limit on operating hours for the emergency generator of 200 hrs/yr, including 100 hrs/yr for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations, and the exclusive use of ULSD. The fire pump engine will be operated for a maximum of 500 hours a year.

The BACT selection for the Engines is summarized below in Table 4-8:

Table 4-8: BACT Summary for the Engines Greenhouse Gases – GHG Control

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Use of ULSD	Comply with NSPS Subpart IIII and exclusive use of ULSD. BACT is also limiting operating hours to 200 hours/yr including 100 hrs/yr for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations. The fire pump engine will be operated for a maximum of 500 hours per year.	N/A	Comply with NSPS IIII

Diesel Storage Tank (TK1) – BACT Review

Diesel Storage Tank (TK1) – VOC Emissions

Applicant's Proposal

Characterization of Emissions – Tank

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.

Identification of VOC Control Technologies – Tank (Step 1)

The Plant 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 of the application, 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.

On October 4, 2023, EPA proposed NSPS Subpart Kc, which would apply to certain volatile organic liquid storage vessels, including petroleum liquid storage vessels.[53] 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. The Plant has nonetheless evaluated technical feasibility and other factors for these control options, along with use of submerged filling and tank design.

Elimination of Technically Infeasible VOC Control Options – Tank (Step 2)

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

[53] 88 Fed. Reg. 68535 (October 4, 2023)

The Plant 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.[54] Therefore, use of submerged filling and light or reflective tank surface colors are the only technically feasible control options.

Summary and Ranking of Remaining VOC Controls – Tank (Step 3)

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.

Evaluation of Most Stringent VOC Controls – Tank (Step 4)

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.[55]

Selection of Emission Limits for VOC BACT (Step 5)

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.

[54] 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

[55] 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.

EPD Review/Conclusion – Fuel Oil Storage Tank VOC Emissions Control

In comparing the facility to other similar units, the Division agrees with the proposed BACT of good maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and selection of tank roof and shell paint colors which have low solar absorptance.

The BACT selection for the Engines is summarized below in Table 4-9:

Table 4-9: BACT Summary for the Tank

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Maintenance Practices Submerged fill pipe Low Solar Absorption Paint Colors	-	-	-

Fuel Gas Heaters (WBH2 – WBH4) – BACT Review

Fuel Gas Heaters (WBH2 – WBH4) – NOx Emissions

Applicant's Proposal

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.

NOx Formation – Heaters

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.

Identification of NO_X Control Technologies – Heaters (Step 1)

The Plant 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 of the application, 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).

Elimination of Technically Infeasible NO_X Control Options – Heaters (Step 2)

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

The Plant 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 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.

Summary and Ranking of Remaining NO_X Controls – Heaters (Step 3)

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.

Evaluation of Most Stringent NO_X Controls – Heaters (Step 4)

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.

Selection of Emission Limits for NO_X BACT (Step 5)

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, the Plant 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.[56] 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.

EPD Review – Heaters NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[57]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM_{10}, CO, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Heaters NOx Control

The technically feasible control technologies for NOx emission control for heaters are use of natural gas, good combustion practices, and ultra-low NOx burners.

The only facilities that state the NOx emission limit of 0.011 lb/MMBtu as BACT for the heaters of varied size in the RBLC database are 20% of the heater entries, some for example are;

- Colbert Combustion Turbine Plant, 10 MMBtu/hr, 0.011 lb/MMBtu
- Nemadji Trail Energy Center, 100 MMBtu/hr, 0.011 lb/MMBtu
- Jackson Energy Center, 96 MMBtu/hr, 0.010 lb/MMBtu

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of use of natural gas, good combustion practices, and ultra-low NOx burners.

[56] 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.

[57] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

The BACT selection for the Heaters is summarized below in Table 4-10:

Table 4-10: BACT Summary for the Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Natural Gas, good combustion practices, and ultra-low NOx burners	9 ppmvd, corrected to 3% O2, or 0.011 lb/mmBtu	-	Biennial tune-up

Fuel Gas Heaters (WBH2 – WBH4) – CO Emissions

Applicant's Proposal

CO Formation – Heaters

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.

Identification of CO Control Technologies – Heaters (Step 1)

The Plant 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 of the application, Table E-22, 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 (e.g., tune-ups). Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

Elimination of Technically Infeasible CO Control Options – Heaters (Step 2)

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. The Plant 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 are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for CO emissions.

<u>Summary and Ranking of Remaining CO Controls – Heaters (Step 3)</u>

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.

<u>Evaluation of Most Stringent CO Controls – Heaters (Step 4)</u>

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.

<u>Selection of Emission Limits for CO BACT (Step 5)</u>

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, the Plant 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.[58] Measurements of CO (and O_2) will be conducted using the procedures of ASTM D 6522, CTM030, or EPA reference methods 10 and 3A.

<u>EPD Review – Heaters CO Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis and used the following resources and information:

[58] *Id*.

- USEPA RACT/BACT/LAER Clearinghouse[59]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Heaters CO Control

The technically feasible control technologies for CO emission control for heaters are use of natural gas and good combustion practices.

The only facilities that state a CO emission limit of 0.074 lb/MMBtu as BACT for the heaters of varied size in the RBLC database are 42% of the heater entries, some for example are;

- Michigan State University, 25 MMBTu/hr, 0.080 lb/MMBTu
- Colbert Combustion Turbine Plant, 10 MMBTu/hr, 0.080 lb/MMBTu
- Indeck Niles, LLC, 27 MMBTu/hr, 1.11 lb/MMBTu

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of use of natural gas and good combustion practices.

The BACT selection for the Heaters is summarized below in Table 4-11:

Table 4-11: BACT Summary for the Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Natural Gas and good combustion practices	100 ppmvd, corrected to 3% O2, or 0.074 lb/mmBtu	-	Biennial tune-up

Fuel Gas Heaters (WBH2 – WBH4) – VOC Emissions

Applicant's Proposal

VOC Formation – Heaters

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.

[59] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Identification of VOC Control Technologies – Heaters (Step 1)

The Plant 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 of the application, 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.

Elimination of Technically Infeasible VOC Control Options – Heaters (Step 2)

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 are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for VOC emissions.

Summary and Ranking of Remaining VOC Controls – Heaters (Step 3)

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.

Evaluation of Most Stringent VOC Controls – Heaters (Step 4)

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.

Selection of Emission Limits for VOC BACT (Step 5)

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.

EPD Review – Heaters VOC Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the VOC BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[60]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Heaters VOC Control

The technically feasible control technologies for VOC emission control for heaters are use of natural gas and good combustion practices.

The only facilities that state a VOC emission limit of 0.010 lb/MMBtu as BACT for the heaters of varied size in the RBLC database are 23% of the heater entries, some for example are;

- Orange County Advanced Power Station, 16.8 MMBtu/hr, 0.005 lb/MMBtu
- Gas Treatment Plant, 32 MMBtu/hr, 0.006 lb/MMBtu
- Holland Board of Public Works, 3.7 MMBtu/hr, 0.0081 lb/MMBtu

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of use of natural gas and good combustion practices.

The BACT selection for the Heaters is summarized below in Table 4-12:

Table 4-12: BACT Summary for the Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Natural Gas and good combustion practices	20 ppmvd, corrected to 3% O2 or 0.010 lb/MMBtu	-	Fuel Records

[60] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Fuel Gas Heaters (WBH2 – WBH4) – PM Emissions

Applicant's Proposal

PM Formation – Heaters

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.

Identification of PM Control Technologies – Heaters (Step 1)

The Plant 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 of the application, 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.[61] 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.

Elimination of Technically Infeasible PM Control Options – Heaters (Step 2)

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

Summary and Ranking of Remaining PM Controls – Heaters (Step 3)

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.

Evaluation of Most Stringent PM Controls – Heaters (Step 4)

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.

[61] 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).

Selection of Emission Limits for PM BACT (Step 5)

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.

EPD Review – Heaters PM Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[62]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Heaters PM Control

The technically feasible control technologies for PM emission control for heaters are use of natural gas and good combustion practices.

The only facilities that state the PM emission limits in the range of 0.007 to 0.0075 lb/MMBtu as BACT for the heaters of small size in the RBLC database are 47% of the heater entries, some for example are;

- Orange County Advanced Power Station, 16.8 MMBtu/hr, 0.007 lb/MMBtu
- Belle River Combined Cycle Plant, 20.8 MMBtu/hr, 0.0072 lb/MMBtu
- Holland Board of Public Works, 3.7 MMBtu/hr, 0.007 lb/MMBtu for PM and 0.0075 for $PM_{2.5}$ and PM_{10}

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of use of natural gas and good combustion practices.

[62] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

The BACT selection for the Heaters is summarized below in Table 4-13:

Table 4-13: BACT Summary for the Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Natural Gas and good combustion practices	0.007 lb/MMBtu	-	Fuel Records

Heaters (WBH2-WBH4) – GHG Emissions

Applicant's Proposal

GHG Formation – Heaters

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.

Identification of GHG Control Technologies – Heaters (Step 1)

Based on the RBLC search results provided in Appendix E of the application, 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.

Elimination of Technically Infeasible GHG Control Options – Heaters (Step 2)

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

Summary and Ranking of Remaining GHG Controls – Heaters (Step 3)

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.

Evaluation of Most Stringent GHG Controls – Heaters (Step 4)

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.

Selection of Emission Limits for GHG BACT (Step 5)

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.

EPD Review – Heaters GHG Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the GHG BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[63]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Heaters GHG Control

The technically feasible control technologies for GHG emission control for heaters are use of natural gas and good combustion practices.

There are no emission limits for GHG on the fuel gas heaters, BACT is suggested to be exclusive use of natural gas. The Division agrees with this and the proposed BACT control technology of use of natural gas and good combustion practices.

The BACT selection for the Heaters is summarized below in Table 4-14:

Table 4-14: BACT Summary for the Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Natural Gas and good combustion practices	Exclusive use of natural gas	-	Fuel Records

[63] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Applicant's Proposal – Summary of Proposed BACT

Table 4-15 summarizes the proposed BACT limits and compliance demonstration methods for each of the Project's proposed emission units.

Table 4-15. 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	CEMS, 12-mo rolling average

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
				startup, shutdown, and fuel switching	
	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	Fuel supplier documentation
		Distillate oil		Ultra-low sulfur distillate oil (15 ppm sulfur)	
	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
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	Comply with NSPS Subpart IIII. Limit operating hour to 200 hr/yr, including 100	Comply with NSPS Subpart IIII

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
				hrs/yr for maintenance checks and readiness testing, 50 hr/yr may be used in non-emergency service.	
Fire Water Engine Pump	NO_X, 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	NO_X	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

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
	GHG	Natural gas	Natural gas, good combustion practices	Exclusive use of natural gas	Fuels records

5.0 TESTING AND MONITORING REQUIREMENTS

Requirements for NO_x

To reasonably assure compliance with the BACT NO_x emission limitations, the Permittee must install, calibrate, operate, and maintain a NO_x CEMS for periodic monitoring of NO_x emissions from each combustion turbine.

As discussed in the BACT analysis, 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.

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

Sources demonstrating compliance with the NOx emission limits via a CEMS are not subject to the requirement to perform initial and annual NOx stack tests.[64] Initial compliance with the applicable NOx emission limits will be demonstrated by comparing the arithmetic average of the NOx emissions measurements taken during the initial RATA to the NOx emission limit under this subpart.[65]

Per 40 CFR 60.4340(b)(2)(iv), units operating without water injection that are regulated by 40 CFR Part 75 may rely on the 40 CFR Part 75 Appendix E procedures for documenting ongoing compliance with the NSPS Subpart KKKK NOx standards with approval from the state. The Plant CTs will operate without water injection during natural gas combustion.

Water injection will be required for fuel oil combustion. 40 CFR 60.4335 establishes NOx monitoring options for water injection, including use of a CEMS, but does not explicitly state that the Part 75 procedures may be relied upon. However, NSPS Subpart KKKK specific requirements for a CEMS are detailed in 40 CFR 60.4345, including an option to rely on a CEMS installed and certified per 40 CFR Part 75.32. Therefore, the use of a NOx CEMS meeting the requirements of 40 CFR Part 75 Appendix E should be sufficient for NSPS Subpart KKKK NOx compliance monitoring purposes.

The proposed primary BACT limits of 2.5 ppmvd and 5.0 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different NOx emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. The Plant therefore proposes a secondary BACT limit per turbine of 168.3 tpy on a rolling 12-month basis to ensure the minimization of emissions during startup/shutdown periods.

[64] 40 CFR 60.4340(b), 40 CFR 60.4405

[65] 40 CFR 60.4405(c) and (d)

The Plant will determine and record the mass emission rate (lb/hr) of NOx from each combustion turbine for each hour or portion of each hour of operation. The mass emission rate from each combustion turbine will be calculated by multiplying the total NOx emissions in units of pounds per million Btu, determined in accordance with the procedures of 40 CFR Part 75, Section 3 of Appendix F, by the total heat input for that hour determined in the accordance with the procedures of 40 CFR 75, Section 5.5 of Appendix F.

Requirements for CO

Compliance with the BACT CO emission limitations for each combustion turbine must be demonstrated by an initial performance test using Method 10, the method for compliance determination. For each of the simple-cycle systems (Combustion Turbines CT8, CT9, and CT10), separate tests must be conducted while burning natural gas and ultra-low sulfur diesel fuel. Periodic testing will be required, on each combustion turbine, no more than 60 months following the previous performance test.

The proposed primary BACT limits of 3.5 ppmvd and 5.0 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different CO emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. The Plant therefore proposes a secondary CO BACT limit per turbine of 1004.6 tpy to ensure the minimization of emissions during startup/shutdown periods.

Requirements for SO_2

NSPS Subpart KKKK requires the total sulfur content of the fuel to be monitored. However, if a fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input, then the Permittee may elect not to monitor the sulfur content of that fuel. In keeping with the provisions of 40 CFR 60.4365, the Permittee will therefore demonstrate that neither the pipeline quality natural gas nor the ultra-low sulfur diesel fuel contains potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu.

The Acid Rain regulations require that SO_2 mass emissions from each combustion turbine be measured and recorded. One option for satisfying that requirement is to use applicable procedures specified in Appendix D to 40 CFR Part 75 for estimating hourly SO_2 mass emissions. SO_2 mass emissions from firing pipeline quality natural gas will be estimated using the regulatory default SO_2 emission rate of 0.060 lb SO_2/MMBtu and the applicable quantity of natural gas burned in the combustion turbine. The heat content for the natural gas is 1020 Btu/scf. SO_2 mass emissions from Combustion Turbines CT8, CT9, and CT10 firing ultra-low sulfur diesel fuel will be calculated based on the average sulfur content and heat content of that oil and the quantity of that oil which is burned. The sulfur content and heat content of that oil will be provided by appropriate certifications from the fuel suppliers. The Plant will also have the flexibility to monitor the sulfur content and heat content of that oil using “as-received” samples instead of fuel-supplier certifications. The Division believes that this method of compliance is acceptable provided that the sulfur content of all oil delivered meets the applicable limit, which is 15 ppm.

Requirements for VOC

Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for long-term, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Plant. The performance tests for carbon monoxide and volatile organic compounds shall be conducted concurrently.

With the use of good combustion practices, pipeline quality natural gas, and Ultra-low Sulfur Distillate (USLD) fuel, the Division concurs, that no monitoring of VOC will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for Particulate Matter and Opacity

Natural gas and USLD fuel are both low-ash fuels. Consequently, the Division believes each simple-cycle system will emit negligible amounts of particulate matter and visible emissions. Each system will be tested while its combustion turbine fires natural gas and also while it fires ultra-low sulfur diesel. Compliance with the particulate matter and visible emissions limits will be determined using Method 5T and Method 9, respectively. Method 9 also will be the basis for periodic monitoring of visible emissions, when the Division deems necessary.

With the use of good combustion practices, pipeline quality natural gas, and USLD fuel, the Division concurs, that no monitoring of PM_{10} will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for GHG

Compliance with the proposed GHG BACT limit will be demonstrated by monitoring fuel consumption and performing calculations. The facility will have conditions in the permit that require monthly recordkeeping of natural gas and fuel oil usage in each combustion turbine.

Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2 emission factor from Appendix G to 40 CFR 75, the CH_4 and N_2O emission factors from Subpart C to 40 CFR 98, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO2, 25 for CH4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12- month rolling total tons per year emission rate does not exceed this limit.

CAM Applicability:

The Combustion Turbines (Source Codes: CT8 - CT10) are subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The Combustion Turbines (Source Codes: CT8 - CT10) will use a water injection system to control NOx emissions while firing fuel oil. Refer to Section 3.0 “Review of Applicable Rules and Regulations” of this document for more detail on the CAM requirements for Combustion Turbines (Source Codes: CT8 - CT10).

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exists for NO_2, CO, $PM_{2.5}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the Plant triggers PSD review for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), and sulfuric acid mist (H_2SO_4) emissions. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_2, CO, $PM_{2.5}$, PM_{10}, Ozone (O_3), and lead. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), nitrogen oxides (NOx), volatile organic compounds (VOC), and carbon monoxide (CO) that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment.

VOC does not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Paulding County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_X limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), and sulfuric acid mist (H_2SO_4) emissions increases at the Plant would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment, as long as an evaluation confirms that sufficient margin remains available to accommodate the impact of the project. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

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.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. According to EPA guidance dated April 17, 2018, permitting authorities may use a SIL for $PM_{2.5}$, so long as it is justified, of 1.2 ug/m3 for the 24-hour standard and 0.2 ug/m3 for the annual standard.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
$PM_{2.5}$	Annual	0.2	--
	24-Hour	1.2	--
PM_{10}	Annual	1	--
	24-Hour	5	10
NO_X	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS Primary / Secondary (ug/m^3)	NAAQS Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	12 / 12	--
	24-Hour	35 / 35	--
NO_X	Annual	100 / 100	0.053 / 0.053
	1-Hour	189 / None	0.100 / None
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Plant, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_X, SO_2, PM_{10}, and $PM_{2.5}$; no increments have been established for CO. The PSD Increments are further broken into Class I, II, and III Increments. The Plant is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
$PM_{2.5}$	Annual	1	4
	24-Hour	2	9
PM_{10}	Annual	4	17
	24-Hour	8	30
NO_X	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increase or decrease after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the SIL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as January 30, 1980, and for NO_2 as April 12, 1991.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Section 6 of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of CO or PM_{10} above the appropriate SIL, and ambient impacts of $PM_{2.5}$ are below the SIL for the annual standard. Because the emissions increase from the proposed project result in ambient impacts less than the SIL, and sufficient margin remains available below the NAAQS to accommodate the modeled impacts, no further PSD analyses were conducted for these pollutants.

However, ambient impacts above the SILs were predicted for NOx and $PM_{2.5}$ for the 1-hour and 24-hour averaging periods respectively, requiring NAAQS and Increment analyses be performed for NOx and $PM_{2.5}$.

Table 6-4: Class II Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	1-hour**	691,784.00	3,703,684.00	**15.01**	7.5	**Yes**
	Annual	691,900.00	3,703,723.00	0.43101	1	No
PM_{10}	24-hour	694,000.00	3,703,523.00	2.132	5	No
	Annual	695,404.98	3,704,272.44	0.079	1	No
$PM_{2.5}$	24-hour	695,500.00	3,803,523.00	**1.46**	1.2	**Yes**
	Annual	695,404.98	3,704,272.44	0.0802	0.2	No
CO	1-hour	691,400.00	3,702,823.00	432.68	2000	No
	8-hour	694,000.00	3,703,523.00	230.20	500	No

* Secondary $PM_{2.5}$ impacts were estimated with the MERP approach using the project NO_X and SO_2 emissions at the proposed facility.

** The DMU expanded the 100-meter spaced 1-hour NO_2 modeling receptor grid to include the entire significant impact area (SIA). The refined grid resulted in a similar max concentration but produced a slightly larger SIA.

Table 6-5: Class I Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	Annual	727,039.38	3,666,020.78	0.00541	2.5	No
PM_{10}	24-hour	719,140.48	3,660,592.01	0.10789	0.3	No
	Annual	727,039.38	3,666,020.78	0.00383	0.2	No
$PM_{2.5}$	24-hour	719,900.00	3,661,021.73	0.1357	0.27	No
	Annual	727,039.38	3,666,020.78	0.0043	0.05	No

* Secondary $PM_{2.5}$ impacts were estimated with the MERP approach using the NO_X and SO_2 emissions at the proposed facility. The applicant used the most conservative Class II MERPs for the class I SIL. The DMU followed the distance-based Class I MERP approach.

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for PM_{10} and CO, as well as the annual $PM_{2.5}$ NAAQS. However, maximum modeled impacts were above the SILs for 1-hour NO_2 and 24-hour $PM_{2.5}$ standards. Therefore, a Full Impact Analysis was conducted for 1-hour NO_2 and 24-hour $PM_{2.5}$.

Significant Impact Area

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the SIL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be less than 50 kilometers for 1-hr NO_2 and 24-hour $PM_{2.5}$. To be conservative, regional source inventories for both pollutants were prepared for sources located within 50 kilometers of the facility.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. The Plant requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. The Plant reviewed the data received and calculated the distance from the mill to each facility in the inventory. All sources more than 50 km outside the SIA were excluded.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 50 kilometers from the mill were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application and the attached modeling report.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-6. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 6-6: NAAQS Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO_2	1-hour	703,284.00	3,695,484.00	151.645	30.30	182.95	188.7	No
$PM_{2.5}$	24-hour	695,600.00	3,703,623.00	1.086	16.2	18.166	35.0	No

* The applicant converted the maximum 1-hour short term NOx emissions directly to TPY for the Tenaska Georgia Generating Station (TGGS) facility, one of the sources in the regional inventory. The DMU used the long-term emissions from the inventory as the basis for the offsite MERPS, consistent with the way the other facilities in the regional emissions inventory were analyzed. The DMU obtained a lower $PM_{2.5}$ secondary impact as a result.

** The applicant included a facility in the 1-hour NO_2 inventory that was confirmed with SSPP to have ceased operation in 2016. After the DMU removed two exceeding receptors that were located inside the property of a separate inventory facility, all other receptors were below the NAAQS.

As indicated in Table 6-6 above, the total modeled impact for the 24-hour averaging period for $PM_{2.5}$ does not exceed the corresponding NAAQS. All of the other total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 6-7.

Table 6-7: Increment Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
$PM_{2.5}$	24-hour	695,500.00	3,703,623.00	1.266	9	No

*DMU determined that the inventory sources that the applicant included in their modeling were not increment consumers.

Table 6-7 demonstrates that the impacts are below the corresponding increments for $PM_{2.5}$ for the 24-hour averaging period even with the conservative modeling assumption that all NAAQS sources were Increment sources.

Ambient Monitoring Requirements

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

The Class I area within approximately 200 kilometers of the Plant is the Cohutta Wilderness Area, located approximately 150 kilometers north-northeast of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of this Class I area.

Six Class I areas exist within a 300 km range from the Plant facility: Okefenokee Wilderness (GA), Sipsey Wilderness (AL), Cohutta Wilderness (GA), Shining Rock Wilderness (NC), Joyce Kilmer (NC), and Great Smoky Mountains National Park (TN). The USDA Forest Service, U.S. Fish and Wildlife Service (FWS), and the National Park Service are the designated Federal Land Managers (FLMs) responsible for oversight of all six of these Class I areas.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

As required, an analysis of the Plant's potential impact on soils and vegetation in the vicinity of the Project was performed by comparing maximum modeled concentrations from the SIL analysis 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 **Error! Reference source not found.**. 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 7-1: Comparison of Modeled Concentrations to Secondary NAAQS

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m^3)	Secondary Impact (ug/m^3)	Total Concentration (ug/m^3)	Secondary NAAQS (ug/m^3)
NO_2	Annual	0.43101	N/A	0.43101	100
PM_{10}	24-hour	2.132	N/A	2.132	150
$PM_{2.5}$	24-hour	1.3929	0.0627	1.46	35
	Annual	0.079	N/A	0.079	15

Growth

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.

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Plant. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NO_X and PM_{10} emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two-colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and have determined that the visual impact criteria (*delta E* and *Contrast*) at the affected sensitive receptors are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area for the Class II area of interest, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

As an additional refinement to the Level II analysis, the NOx emission rate was scaled by 75 percent following the Ambient Ration Method to account for the conversion of NOx to NO_2 in the atmosphere, since the latter is the specific visibility-impairing species. All other parameters were input as Level I default options. A background visual range of 25 kilometers was used for the Plant.

See the division review results in Table 7-2 below.

Table 7-2: Level 2 VISCREEN Results: Chattahoochee Bend State Park

Background	Theta	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	160	11.9	9	2.18	2.030	0.05	0.019
	140				2.00	0.736	0.05	-0.023

* VISCREEN was run using a level 2 analysis for the worst-case fuel oil operating scenario, which consists of maximum 100% load 1-hour emission rates of filterable particulate matter, NOx, and primary SO_4. The class II area that is located within the project's largest SIA was Chattahoochee Bend State Park which restricts public access to sunrise to sunset each day. Only the worst-case daytime stability classifications were considered (6 AM to 6 PM). The angle range of wind speeds that can impact the Class II area were large due to the State Park's proximity to the facility. VISCREEN assumes steady state wind vectors which would not necessarily hold true in too large a wind direction sector. Wind directions were categorized into two adjacent 22.5-degree sectors from which the worst-case daytime stability class was selected. The analysis of KATL surface data file from 2017-2021 determined the worst-case scenario to be stability class D with the wind speed 3 m/s. There are no class I protected integral scenic vistas or terrain views in the area, therefore the TERRAIN results were not considered.

The results of the Level II VISCREEN analysis show that the screening criteria are not exceeded at any of the sensitive receptors when evaluated using the Level II input parameters. Therefore, the proposed modifications to facility are not anticipated to cause adverse impacts on visibility at the sensitive receptors in the area surrounding the mill.

Moreover, an analysis of the Class II increment inventory at the Plant indicates that, since 1975, decreases in actual emissions of visibility-affecting pollutants from the facility far exceed any corresponding increases in potential emissions of these pollutants. Because the perception of industrial plumes has not been an issue in the past, this indicates there is little reason to expect visible industrial plumes from this site will be a substantial future issue.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the natural gas and distillate oil fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. The Plant referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

Initial Screening Analysis Technique

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

Table 7-3 summarizes the AAC levels and MGLCs of the eleven TAPs. The maximum 15-minute impact is based on the maximum 1-hour modeled impact multiplied by a factor of 1.32. As shown in Table 7-3, the modeled MGLCs for all eleven TAPs are below their respective AAC levels.

Table 7-3. Modeled MGLCs and the respective AACs.

TAP	Averaging Period	AAC (μg/m^3)	Max Modeled Conc. (μg/m^3)
Acrolein	Annual	0.02	0.00002
	15-Minute	23	0.02865
Arsenic	Annual	0.000233	0.000022
	15-Minute	0.2	0.0192
Benzene	Annual	0.13	0.000401
	15-Minute	1600	1.0952
1,3-Butadiene	Annual	0.03	4.92e-6
	15-Minute	1100	0.00737
Cadmium	Annual	0.00556	2.92e-5
	15-Minute	30	0.00105
Chromium II/III	24-Hour	1.2	0.00259
Formaldehyde	15-Minute	245	0.563
	Annual	1.1	0.00195
Lead	3-month rolling	0.15	0.00766**
Manganese	Annual	0.05	0.00131
	15-Minute	500	1.35
Selenium	24-Hour	0.48	0.0506
Sulfuric Acid	24-Hour	2.4	0.1201
	15-Minute	300	0.8563

* No location information is available because the applicant derived MGLC values as a sum of all domain-wide maximum concentrations by individual sources.

**It is a sum of the maximum 24-hour modeled concentration (0.00296 μg/m3) and the 2022 background concentration (0.0047 μg/m3) at the Rome, GA monitor. A maximum 24-hour modeled concentration is a more conservative estimate compared to a 3-month rolling average modeled concentration.

*** The applicant took the maximum annual value for the 5-year period. The DMU took the 5-year average value.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-077-0001-V-05-2.

Section 1.0: Facility Description

"The Plant" applied for a permit to construct three (3) advanced class, dual-fuel simple-cycle combustion turbine (CT) units at Plant Yates ("the Plant"), located in Coweta County, Georgia. The proposed project will construct the proposed CT units and will include installation of new associated equipment, such as an emergency generator, an emergency fire water pump engine, and three fuel gas heaters.

Section 2.0: Requirements Pertaining to the Entire Facility

No conditions in Section 2.0 are being added, deleted or modified as part of this permit action.

Section 3.0: Requirements for Emission Units

Added the new combustion turbines CT-8 through CT-10, the emergency generator, the emergency fire water pump engine, and three gas heaters to the equipment table.

New Conditions 3.2.4 and 3.2.5 contain the Heat Input Limits for the Stationary Combustion Turbines.

Conditions 3.3.1 and 3.3.2 contain the 40 CFR 63 Subpart DDDDD requirements for the water bath heater and was modified to include the new water bath heaters.

New Conditions 3.3.3 through 3.3.5 contain the 40 CFR 60 Subpart KKKK requirements for the combustion turbines.

New Condition 3.3.6 contains the 40 CFR 60 Subpart TTTT requirements for the combustion turbines.

New Conditions 3.3.7 through 3.3.10 contain the 40 CFR 52 (PSD) and 40 CFR 60 Subpart KKKK emission limits and requirements for the combustion turbines.

New Conditions 3.3.11 and 3.3.14 contain the 40 CFR 63 Subpart YYYY requirements for the combustion turbines.

New Condition 3.3.15 requires the water bath heaters to only fire pipeline quality natural gas.

New Condition 3.3.16 contains the PSD emission limits for the water bath heaters.

New Condition 3.3.17 requires the use of a submerged fill pipe for the fuel oil storage tank.

New Conditions 3.4.10 and 3.4.11 contain the Georgia State Rule d and Georgia State Rule nnn requirements for the combustion turbines.

Section 4.0: Requirements for Testing

General Test Method Requirements in Condition 4.1.3 were modified.

New Conditions 4.2.1 through 4.2.5 contain the special test requirements for the combustion turbines.

Section 5.0: Requirements for Monitoring

Condition 5.2.1 was modified to include the new CEMs monitoring requirements for the combustion turbines.

Condition 5.2.7 was modified to include the new water bath heaters in the heater tune-up requirements.

New Condition 5.2.8 requires fuel quantity usage monitors on the water bath heaters.

New Condition 5.2.9 contains the monitoring requirements for the combustion turbines.

New Conditions 5.2.10 and 5.2.11 require fuel supplier certifications for the pipeline quality natural gas and fuel oil fired in the combustion turbines.

New Conditions 5.2.12 through 5.2.17 states the quality assessment requirements of the NOx CEMs and the CO CEMs for the combustion turbines.

New Conditions 5.2.18 through 5.2.23 states the 40 CFR 64 (CAM plan) requirements for the combustion turbines.

New Condition 5.2.24 contains additional CMS requirements for the combustion turbines.

New Condition 5.2.25 contains additional tune up monitoring requirements for the water bath heaters.

Section 6.0: Other Recordkeeping and Reporting Requirements

Condition 6.1.7a. was modified to include excess emissions limitations for the combustion turbines.

Condition 6.1.7b. was modified to include exceedances for the water bath heaters and the combustion turbines.

Condition 6.1.7c. was modified to include excursions for the combustion turbines.

New Condition 6.1.9 was added to include the additional reporting requirements for the combustion turbines.

Conditions 6.2.13 through 6.2.15 were modified to include the additional recordkeeping and reporting requirements for the new water bath heaters.

New Conditions 6.2.17 through 6.2.19 were added to require recordkeeping of fuel usage requirements in the combustion turbines.

New Conditions 6.2.20 through 6.2.23 were added to require recordkeeping of verification of compliance with NO_x emission limits for the combustion turbines.

New Conditions 6.2.24 through 6.2.26 were added to require recordkeeping of verification of compliance with CO emission limits for the combustion turbines.

New Conditions 6.2.27 through 6.2.29 were added to require recordkeeping of verification of compliance with greenhouse gas emission limits for the combustion turbines.

New Conditions 6.2.30 through 6.2.33 were added to require recordkeeping of verification of compliance with operational limits for the combustion turbines.

New Condition 6.2.34 was added to state the quarterly reporting requirements for the combustion turbines.

New Condition 6.2.35 and 6.2.36 were added to state the Georgia Rule (nnn) recordkeeping and reporting requirements for the combustion turbines.

New Condition 6.2.37 through 6.2.41 were added to state the 40 CFR 63 Subpart YYYY recordkeeping and reporting requirements for the combustion turbines.

New Condition 6.2.42 was added to state the construction and startup notification requirements.

New Conditions 6.2.43 and 6.2.44 were added to state the special testing requirements.

Section 7.0: Other Specific Requirements

Condition 7.9.7 was modified to include the combustion turbines.

Conditions 7.14.1 and 7.14.2 were added to provide the construction and startup requirements of the project.

Condition 7.15.1 was modified to include the combustion turbines for the requirements of the Cross State Air Pollution Rule (CSAPR).

APPENDIX A

Draft Revised Title V Operating Permit Amendment

Newnan (Coweta County), Georgia

APPENDIX B

Plant Yates Steam-Electric Generating Plant PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. TV-802465 dated December 8, 2023
2. Additional Information Package Dated January 18, 2024

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review