

Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

July 28, 2025

Facility Name: Bowen Steam-Electric Generating Plant

City: Cartersville

County: Bartow

AIRS Number: 04-13-015-00011

Application Number: TV-905935

Date Application Received: March 5, 2025

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 Bowen Steam-Electric Generating Plant (Plant Bowen) referred to as “The Plant” for a permit to construct and operate up to four (4) combined-cycle (CC) electric generating units at Plant Bowen located in Bartow County, Georgia.

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include the four (4) combined-cycle (CC) electric generating units. The proposed project will include construction of the four (4) combined-cycle (CC) electric generating units arranged in a 1-on-1 configuration, each of which includes an advanced dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator. Each proposed CT unit will be equipped with a selective catalytic reduction (SCR) to minimize nitrogen oxide (NO_x) emissions and an oxidation catalyst to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions.

Associated equipment will include the installation of four (4) multi-cell wet mechanical induced draft cooling towers, four (4) 1,500 kw emergency generators, two (2) 500 kw emergency generators, two (2) 350 hp emergency fire water pump engines, four (4) 8.61 MMBtu water bath heaters with ultra-low NO_x burners, and four (4) fixed-roof 2.3 million gallon distillate oil storage tanks.

The CT will be capable of firing either pipeline quality natural gas or distillate oil. When firing natural gas, dry low-NO_x (DLN) combustors will reduce NO_x formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_x formation.

The modification of Plant Bowen 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 (PM₁₀), particulate matter with an aerodynamic diameter of 2.5 microns and smaller (PM_{2.5}), sulfur dioxide (SO₂), nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO₂e), lead (Pb) and sulfuric acid mist (H₂SO₄). 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 PM, PM₁₀, PM_{2.5}, SO₂, NO_x, VOC, CO, and GHG in terms of carbon CO₂e and H₂SO₄ emissions increase was above the PSD significant level threshold.

Plant Bowen is located in Bartow County, which is classified as “attainment” or “unclassifiable” for SO₂, PM_{2.5} and PM₁₀, NO_x, CO, and ozone (VOC).

The EPD review of the data submitted by Plant Bowen 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 proposed project provides for the application of Best Available Control Technology (BACT) for the control of PM, PM₁₀, PM_{2.5}, SO₂, NO_x, VOC, CO, and GHG in terms of CO₂e and H₂SO₄, 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 300 km of the facility. It has further been determined that the proposed project 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 Plant Bowen for the modifications necessary to construct and operate up to four (4) combined-cycle (CC) electric generating units at Plant Bowen. 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 March 5, 2025, Bowen Steam-Electric Generating Plant (hereafter “The Plant”) submitted an application for an air quality permit for four proposed CC units that will include installation of new associated equipment, including six emergency generators, two emergency fire water pump engines, four multi-cell mechanical draft cooling towers and four water bath heaters. The facility is located at 317 Covered Bridge Rd in Cartersville, Bartow 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	Y			✓
H ₂ S	Y			✓
Individual HAP	Y	✓		
Total HAPs	Y	✓		
Total GHGs	Y	✓		

Table 1-2 below lists all current Title V permits, 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, 502(b)(10) Changes, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-015-0011-V-05-0	January 13, 2025	Title V Renewal

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 emission rate for that pollutant (as defined in 40 CFR Part 52.21(b)(23)).

Table 3-5 of the application provides the Project annual criteria pollutant potential to emit based on the maximum emitting scenario for the proposed CC units presented in Table 3-1 and Table 3-2 of the application and the potential to emit for associated equipment presented in Table 3-4 of the application. Table 3-6 of the application provides the annual HAP potential to emit.

Emissions of regulated NSR pollutants are based, in part, by assuming no capacity factor limit and: (1) a maximum of 29,600,000 gallons per year of distillate oil fired in each CC; (2) a sulfur content limit of natural gas of 0.5 grains per 100 standard cubic feet; and (3) a sulfur content limit of fuel oil of 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 (4 heaters total); (2) 200 hrs/yr of ultra-low fuel oil combustion for the emergency generators; (3) 500 hrs/yr of ultra-low fuel oil combustion for the emergency fire-water pumps; and (4) 29,600,000 gal/yr each of annual throughput for the Turbine Fuel Diesel Storage Tanks based on all 4 CC units operating on oil at maximum heat input rate for the 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	253.8	25	Yes
¹ PM _{2.5}	462	10	Yes
¹ PM ₁₀	464	15	Yes
VOC	650.9	40	Yes
NO _x	828.1	40	Yes
CO	1,047.8	100	Yes
SO ₂	143.1	40	Yes
Pb	0.2	0.6	No
SAM	218.8	7	Yes
² CO ₂ e	11,031,001	75,000	Yes

(1) TSP is filterable PM emissions only. PM₁₀ and PM_{2.5} includes both filterable and condensable PM emissions.

(2) CO₂e is the number of tons of CO₂ emissions with the same global warming potential as one ton of another greenhouse gas. CO₂e includes CO₂ emissions, CH₄ emissions as CO₂e, and N₂O emissions as CO₂e.

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-905935). 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-905935, is classified as a major modification under PSD because the potential emissions of PM, PM₁₀, PM_{2.5}, SO₂, NO_x, 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 new emission units comprising the project because 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-905935, the Plant has proposed to construct CC Units 7, 8, 9, and 10 (Emission Units IDs CT7/DB7, CT8/DB8, CT9/DB9, and CT10/DB10) and associated equipment.

The primary equipment of the Project includes:

- Four (4) combined-cycle electric generating units, arranged in a 1-on-1 configuration, each of which includes an advanced-class dual-fuel CT generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator. The CTs fire natural gas or ultra-low sulfur distillate oil (ULSD).

Associated equipment associated with the Project includes:

- Four (4) ULSD fuel-fired emergency generators with an output capacity of 1,500 kW,
- Two (2) ULSD fuel-fired emergency generators with an output capacity of 500 kW,
- Two (2) ULSD fuel-fired water pump engines with an output rating of approximately 350 bhp,
- Four (4) ULSD fixed roof distillate oil storage tanks with a nominal capacity of 2.3 million gallons, and
- Four (4) natural gas-fired water bath heaters each with a heat input rating of less than 10 MMBtu/hr.
- Four (4) multi-cell wet mechanical induced draft cooling towers

Combustion Turbines

Annual operation of each proposed CC unit will be limited to a capacity factor based on its design efficiency for purposes of compliance with NSPS Subpart TTTT. Each proposed CC unit is comprised of five major sections: the compressor, the combustor, the power turbine, heat recovery steam generator with natural gas-fired duct burner, and steam turbine generator 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.
- In the combustor, a mixture of fuel and air is introduced and combusted. The CT will be capable of firing either pipeline quality natural gas or distillate oil. When firing natural gas, dry low-NO_x (DLN) combustors will reduce NO_x formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_x formation. Exhaust gases, at high temperature and pressure, are then directed to the turbine section to generate power.
- 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.

- The exhaust gases exiting the CC units will be ducted to a horizontal, natural circulation, three-pressure level HRSG where high, intermediate, and low-pressure steam will be produced and used in the ST to generate additional electricity. Each HRSG will be equipped with natural gas-fired duct burners which can be used to provide additional steam generating capacity only when the CC unit is firing natural gas. SCR and oxidation catalyst systems will be installed in each HRSG to reduce emissions of NO_x, CO and VOC.
- Each proposed CC unit will include a reheat condensing ST designed for variable pressure operation. The ST consist of a combined high-pressure-intermediate pressure turbine and a low-pressure turbine to generate power with the associated generator. The high-pressure portion of each ST receives high-pressure super-heated steam from its associated HRSG and exhausts to the reheat section where it is combined with excess intermediate pressure steam from the HRSG. The HRSG increases the temperature of the steam and returns the steam to the intermediate-pressure section of the ST, which expands to the low-pressure section. The low-pressure ST also receives excess low-pressure superheated steam from the HRSG, exhausting all steam to a water-cooled condenser.

Diesel-Fired Emergency Generator and Fire Water Pump Engines

The proposed Project will include up to four (4) 1,500 kW ULSD-fired emergency generators and (2) 350 hp firewater pump engines associated with the proposed CC units. The Project will also include up to two (2) 500 kW emergency generators associated with support buildings. Each emergency generator will be compression ignition, certified to Tier 2 emission standards, and be operated no more than 200 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. The fire water pump engines will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 500 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. All emergency generators and fire water pump engines will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

Distillate Oil Storage Tank

Each proposed CC unit will be served by an aluminum vertical fixed-roof storage tank, for a total of up to four (4) tanks, for onsite storage of distillate oil to provide reliability and resiliency benefits to the electric system. Each tank will be 90 feet in diameter and have a working capacity of 2.3 million gallons. Emissions of VOC from the tanks will be minimized by equipping each tank with submerged filling to reduce working losses. Each tank roof and shell will be fully insulated to reduce breathing losses.

Water Bath Heaters

The Project will include four (4) natural gas-fired water bath 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.

Cooling Towers

Each proposed CC unit will be served by a multi-cell wet mechanical induced draft cooling tower that will provide cooling water to be used in the condensers for the ST generator exhaust as well as various process heat exchangers. The design circulating water flow rate for each cooling tower is 125,000 gallons per minute (gpm). Each cooling tower will be equipped with high-efficiency drift eliminators that will reduce droplet drift from each tower to 0.0005% of the tower circulating water flow rate.

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.

Only the emergency generators and fire water pump engines are subject to Rule (b). Rule (b) does not apply to the cooling towers and distillate oil tanks because neither is subject to some other emission limitation in Ga. Comp. R. & Regs. Rule 391-3-1-.02(2). Additionally, as discussed below, the proposed CC units and water bath heaters are subject to a more stringent opacity standard in Rule 391-3-1-.02(2)(d)3.

The emergency generators and fire water pump engines are subject to Rules (g) or (mmm) as well as NSPS Subpart IIII. It is expected that the opacity of visible emissions from these sources will be less than 40% because these engines will be certified to meet the “smoke” opacity standards in 40 CFR 1039.105 as part of Tier 2 or 3 certification, as applicable.

Georgia Rule 391-3-1-.02(2)(d) – Fuel-Burning Equipment

Rule (d) limits the PM emissions, visible emissions, and NO_x 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 emergency generators and fire water pump engines are not subject to Rule (d) because these engines will not produce thermal energy to furnish process heat indirectly (i.e., are not fuel-burning equipment). However, thermal energy from the proposed CC units and water bath heaters are used to generate steam or heat water, making them subject to Rule (d).

Rule (d) limits visible emissions from the proposed CC units and water bath heaters to less than 20% except for one six-minute period per hour of not more than 27% opacity. Allowable PM and NOx emissions for the proposed CC units and water bath heaters vary but are subsumed by the more stringent BACT limits.

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 CC units, emergency generator, firewater pump engines, and the gas heaters.

For fuel-burning sources below 100 MMBtu/hr, such as the proposed water bath heaters, emergency generators, and fire water pump engines, 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 for the CC Units and NSPS Subpart IIII for the emergency generators and fire water pump engines.

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 tanks are 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)(yy) – Nitrogen Oxides from Major Sources

Rule (yy) regulates the emissions of NO_x from facilities in the metro Atlanta area (including Bartow County). The rule requires facilities subject to the rule to demonstrate EPD approved Reasonably Achievable Control Technology (RACT) to control NO_x emissions. However, this rule does not apply to sources subject to Rules (jjj), (lll), (mmm), or (nnn) or individual equipment with *de minimis* emissions (potential emissions of NO_x emissions less than 1 tpy).

The proposed CC units are subject to Rule (nnn) and the proposed emergency generators are subject to Rule (mmm). Additionally, the proposed water bath heaters and fire water pump engines will each have *de minimis* emissions of NO_x. Therefore, Rule (yy) is not applicable to any source associated with the Project.

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 (Bartow County) covered by this rule. However, the proposed water bath 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) – NO_x Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity

Rule (mmm) establishes ozone season NO_x emission limits on stationary gas turbines and stationary engines with nameplate output capacities between 100 kWe and 25 MWe used for electricity generation and located in certain counties (including Bartow County).

This rule is not applicable to the proposed CC units because they are too large. This rule is not applicable to either the emergency fire pump engines or the emergency generators. The rule will not apply to the proposed emergency fire pump engines because stationary engines not connected to an electrical generator are exempt from the standards. The emergency generators will also be exempt from the rule because they qualify 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.*”

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 Bartow 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 CC units will be subject to this limitation.

Each of the proposed CC units will include an SCR system that will reduce NO_x emissions to 2 ppm at 15% oxygen when firing natural gas and to 5 ppm at 15% oxygen when firing oil. Therefore, the proposed CC units will satisfy the requirements of Rule (nnn).

Georgia Rule 391-3-1-.02(2)(rrr) – NOx from Small Fuel-Burning Equipment

Rule (rrr) regulates the emissions of NOx from small fuel burning units in the metro Atlanta area (including Bartow 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 NOx equal to or greater than one ton per year. As shown in Appendix C, Table C-9 of the application, the proposed water bath heaters will each have potential NOx 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 CC units, water bath heaters, cooling towers, emergency generators, and fire water pumps are above the de minimis construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i). Further, as discussed in Section 1.2 of the application, PSD permitting is required for multiple pollutants.

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. 4911-015-0011-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 the SIP Permit 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 NOx, Annual SO₂, and Ozone Season NOx)

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, and 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 plant 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, taking into account 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 Kc – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 1984

The requirements of NSPS Subpart Kc apply to storage vessels which have a storage capacity greater than 20,000 gallons that store Volatile Organic Liquids (VOL) for which construction, modification, or reconstruction commenced after July 23, 1984. However, per 40 CFR 60.110b(8), NSPS Kc does not apply to storage vessels of any size storing a liquid with a maximum true vapor pressure less than 0.25 psia. The proposed fuel oil storage tanks at the Plant will have a storage capacity of 2.3 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 0.25 psia (~ 0.01 psia). Therefore, the requirements of NSPS Kc do not apply.

40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The emergency generators and fire water pump engines 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 CC units will be subject to 40 CFR Part 60, Subpart KKKK, which establishes NO_x and SO₂ 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 CC units are subject to NO_x emission standards of 15 ppm, corrected to 15% O₂, or 0.43 lb/MWh, when firing natural gas, and 42 ppm, corrected to 15% O₂, or 1.3 lb/MWh, when firing distillate oil, or 96 ppm, corrected to 15% O₂, 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 CC 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 SO₂

The proposed CC 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 SO₂/MMBtu heat input.

The Plant will comply with the input-based emission standard for SO₂ by utilizing natural gas and distillate oil in the proposed CC units. Both fuels have a sulfur content lower than needed to meet the 0.06 lb SO₂/MMBtu limit.

40 CFR 60 Subpart TTTTa – Proposed Rule: Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units

NSPS Subpart TTTTa establishes GHG emission standards for stationary combustion turbines that commence construction or reconstruction after May 23, 2023, have a base load rating greater than 250 MMBtu/hr, and serve a generator capable of selling more than 25 MW of electricity to a utility power distribution system. Under this subpart, one of three CO₂ standards may apply depending on capacity factors (net generation) during both the previous 12 operating months and 36 calendar

months (3-year rolling). When the capacity factors are more than 20% but less than or equal to 40%, a sliding-scale emission standard of 1,170 to 1,560 lb/MWh-gross applies. If the capacity factors are more than 40%, a sliding-scale emission standard of 800 to 1,250 lb/MWh-gross applies before 2032, after which the standard is lowered to as low as 100 lb/MWh-gross. However, when the capacity factors are 20% or less all that is required is combustion of low-emitting fuels such as natural gas and distillate oil.

If Subpart TTTTa is vacated or repealed, the applicable NSPS will be Subpart TTTT, which imposes a CO₂ emission standard of 1,000 lb/MWh-gross. If both Subparts TTTTa and TTTT are repealed, neither NSPS will apply to the CCs.

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 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 facility is currently classified as an existing major source of HAPs (having potential emissions greater than 25 tpy of total HAP and/or 10 tpy of individual HAP), and the emission units constructed as part of the Project will be subject to the provisions of several subparts of 40 CFR Part 63. The Division 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. In addition to the General Provisions provided in 40 CFR Part 63, Subpart A, the NESHAP subparts potentially applicable to the Project include:

- National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (Subpart YYYY)
- National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (Subpart ZZZZ)
- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Subpart DDDDD)

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 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% O₂, and other associated requirements, including an initial notification and testing. The Plant will comply with the requirements of this subpart by equipping the proposed CC units with oxidation catalysts.

40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generators and fire water pump engines are subject to 40 CFR Part 63, Subpart ZZZZ. Because the emergency generators are new stationary emergency stationary RICE with a site rating of more than 500 hp and will be located at a major source, only initial notification under 40 CFR 63.6645(f) is required according to 40 CFR 63.6590(b)(1)(i). According to 40 CFR

63.6590(c)(6), the fire water pump engines will comply with the requirements of this subpart by complying with NSPS Subpart IIII. No initial notification is required for the firewater pump engines.

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 water bath heaters qualify as process heaters and will be subject to Subpart DDDDD.

The proposed water bath heaters are part of the “designed to burn gas 1 fuels” subcategory and have a heat input rating of less than 10 MMBtu/hr. Therefore, the proposed water bath 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 water bath 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.

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 results 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.

Federal Rule – 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 CC 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 O₂ 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 O₂ 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 anhydrous ammonia in the SCR systems to control NO_x emissions from the proposed CC units. Total anhydrous ammonia stored onsite is greater than the threshold quantity; RMP requirements will thus apply to these systems.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that trigger PSD review for the following pollutants: PM, PM₁₀, PM_{2.5}, NO_x, VOC, CO, SO₂, H₂SO₄, and GHG in terms of CO₂e.

Combined-Cycle Electric Generating Units (Source Codes: CT7/DB7 - CT10/DB10) BACT Review

Combined-Cycle Electric Generating Units (Source Codes: CT7/DB7 - CT10/DB10)-Background

The Plant is in Bartow County, Georgia. The existing facility consists of four steam electric generating units, which primarily burn coal. During normal operation, the Steam Generating Units (SG01, SG02, SG03 and SG04) use flue gas desulfurization (FGD) scrubbers, selective catalytic reduction, and electrostatic precipitators, and exhaust through a separate liner of one of the two 675-foot stacks. There are some operations when it will be necessary to bypass the scrubber. In these cases, the units will exhaust through one of the two existing 1,000-foot stacks. Other support equipment includes one 305 MMBtu/hr and one 486 MMBtu/hr fuel-oil or propane fired start up boiler, a coal handling system, ash handling system, and a material handling system. The key elements of the proposed project include:

- Combined-cycle electric generating units 7, 8, 9, and 10 (CT7/DB7, CT8/DB8, CT9/DB9, and CT10/DB10), arranged in a 1-on-1 configuration, to provide between REDACTED to REDACTED of capacity, depending on the fuel source being utilized. Each unit includes an advanced-class dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator.

Combustion Turbines (CT7, CT8, CT9, and CT10)

The CT is the main component of each proposed CC unit and consists of three major sections: a high-efficiency compressor, a combustor, and a high-efficiency turbine to generate power with the associated generator. In the compressor section, ambient air is drawn through a filter. Once filtered, evaporative cooling is used to cool the air and increase power output when ambient temperatures are sufficiently high. The air is then compressed and directed to the combustor section. In the combustor, a mixture of fuel and air is introduced and combusted. The CT will be capable of firing either pipeline quality natural gas or distillate oil. When firing natural gas, dry low-NO_x (DLN) combustors will reduce NO_x formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_x formation. Exhaust gases, at high temperature and pressure, are then directed to the turbine section to generate power.

In the turbine, the 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.

Heat Recovery Steam Generators (HRSG)

The exhaust gases exiting the CT will be ducted to a horizontal, natural circulation, three-pressure level HRSG where high, intermediate, and low-pressure steam will be produced and used in the ST (Steam Turbine) to generate additional electricity. Each HRSG will be equipped with natural gas-fired duct burners (DB7, DB8, DB9, and DB10) which can be used to provide additional steam generating capacity only when the CT is firing natural gas. SCR and oxidation catalyst systems will be installed in each HRSG to reduce emissions of NO_x, CO, and VOC.

Steam Turbines (ST)

Each proposed CC unit will include a reheat condensing ST designed for variable pressure operation. The ST consists of a combined high-pressure-intermediate-pressure turbine and a low-pressure turbine to generate power with the associated generator. The high-pressure portion of each ST receives high pressure super-heated steam from its associated HRSG and exhausts to the reheat section where it is combined with excess intermediate pressure steam from the HRSG. The HRSG increases the temperature of the steam and returns the steam to the intermediate-pressure section of the ST, which expands to the low-pressure section. The low-pressure ST also receives excess low-pressure superheated steam from the HRSG, exhausting all steam to a water-cooled condenser.

- **Cooling Towers**

Each proposed CC unit will be served by a multi-cell wet mechanical induced draft cooling tower that will provide cooling water to be used in the condensers for the ST generator exhaust as well as various process heat exchangers. The design circulating water flow rate for each cooling tower is 125,000 gallons per minute (gpm). Each cooling tower will be equipped with high-efficiency drift eliminators that will reduce droplet drift from each tower to 0.0005% of the tower circulating water flow rate.

- **Water Bath Heaters**

The Project will include a water bath heater for each proposed CC unit to heat the incoming natural gas above its dew point when necessary to prevent freezing of the gas regulating valves. Each water bath heater will be of the water-bath type and have a maximum heat input of approximately 8.61 MMBtu/hr. The heaters will exclusively fire natural gas and be equipped with ultra-low NO_x burners to minimize NO_x emissions.

- **Distillate Oil Storage Tanks**

Each proposed CC unit will be served by an aluminum vertical fixed-roof storage tank, for a total of up to four (4) tanks, for onsite storage of distillate oil to provide reliability and resiliency benefits to the electric system. Each tank will be approximately 90 feet in diameter and have a working capacity of 2.3 million gallons. Emissions of VOC from the tanks will be minimized by equipping each tank with submerged filling to reduce working losses. Each tank roof and shell will be fully insulated to reduce breathing losses.

- Emergency Generators and Fire Water Pump Engines

The Project will include up to four (4) 1,500 kW emergency generators and (2) 350 hp fire water pump engines associated with the proposed CC units. The Project will also include up to two (2) 500 kW emergency generators associated with support buildings. Each emergency generator will be compression ignition, certified to Tier 2 emissions standards, and be operated no more than 200 hours per year including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. The fire water pump engines will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 500 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. All emergency generators and fire water pump engines will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

Combined Cycle (Source Codes: CT7/DB7 - CT10/DB10) – NO_x 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 NO_x 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 NO_x.

NO_x Formation – Combustion Turbines

There are five (5) primary pathways of NO_x production from turbine combustion processes: thermal NO_x, prompt NO_x, NO_x from N₂O intermediate reactions, fuel NO_x, and NO_x formed through reburning. The three most important mechanisms are thermal NO_x, prompt NO_x, and fuel NO_x.¹ For natural gas-fired units, most NO_x is derived from thermal NO_x. Distillate oils also have low levels of fuel-bound nitrogen (N₂) that contribute to NO_x formation.

NO_x emissions from the proposed CC 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_x emissions are subsequently further oxidized “in-stack” and in the atmosphere to the more stable NO₂ 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.

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

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 (N₂); 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 – CC Units (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 CC units to identify potentially available control options for NO_x emissions from the proposed CC units were conducted.

To identify potentially available control options for NO_x emissions from the proposed CC units, GPC reviewed the following resources:

- A search of the RBLC was conducted to identify NO_x BACT determinations for large natural gas-fired and distillate oil-fired CC units (larger than 25 MW) permitted in the past ten years (i.e., since 2014).
- Permits and associated applications, if available, for large (>25 MW) CC units not found in the RBLC but:
 - Listed as commencing commercial operation within the last five years (i.e., since 2019) in EPA's National Electric Energy Data System (NEEDS) database (11 additional facilities);³

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

³ Available at <https://www.epa.gov/system/files/documents/2024-08/needs-rev-06-06-2024.xlsx>. The following facilities without RBLC entries were identified in NEEDS as having commenced commercial operation within the last five years: AES Huntington Beach, Alamitos Energy Center, Bridgeport Energy, LLC, Big Bend Station, Mankato Energy Center, R D Morrow Sr Generating Plant, Asheville Combined Cycle Plant, Cricket Valley Energy, Birdsboro Power LLC, Hickory Run Energy Station, and West Riverside Energy Center.

- o Listed as planned and under construction in EIA's Annual Electric Power Industry Report, Form EIA-860 (three additional facilities);⁴
- o New and proposed federal and state emission standards; and
- o Interviews with original equipment manufacturers (OEM) and owners/operators of similar large, advanced class CC units.

The results of the RBLC searches for natural gas-fired CC units are provided in Appendix E of the application, Table E-1, while summaries of the reviews of the permits issued to the facilities identified in both NEEDS and EIA-860 are provided in Appendix E of the application, Table E-2. Similarly, the results for distillate oil-fired CC units are provided in Appendix E of the application, Tables E-3 and E-4.

Potentially available control options to reduce NO_x emissions from the proposed CC 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).⁵ 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 CC units when the national emissions standards for this source category were first established in 1977.⁶ 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 NO_x 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

⁴ Available at <https://www.eia.gov/electricity/data/eia860/xls/eia8602023.zip>. The following facilities without RBLC entries were identified in EIA-860 as planned and under construction: Magnolia Power, Shady Hills Combined Cycle Facility, and Trumbull Energy Center.

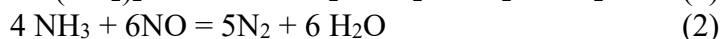
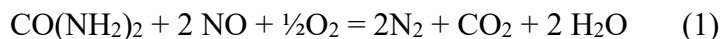
⁵ The Plant notes that multipollutant catalytic post-combustion add-on controls, such as EM_xTM (second-generation SCONO_x absorber technology) and METEORTM have been used to reduce emissions of NO_x, CO, and VOC from combined cycle technology. Separate catalysts are needed for adequate mixing of the dilution air with the exhaust gas to evenly distribute the temperature of the mixed gas across the SCR catalyst to optimize SCR effectiveness.

⁶ 42 Fed. Reg. 53782, 53785 (Oct. 3, 1977).

produce a lean, pre-mixed flame that burns at a lower temperature with less excess oxygen than conventional combustors.⁷

Selective Noncatalytic Reduction

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



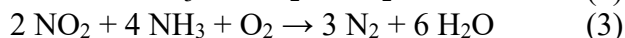
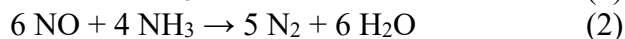
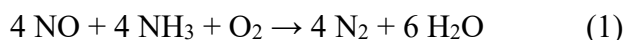
Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls.⁸ An important consideration for SNCR is operating temperature range. The temperature range required for this control option to be effective is approximately 1,600 to 2,000 °F.⁹ 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% O₂).

Selective Catalytic Reduction

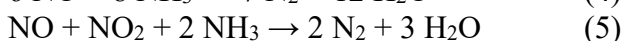
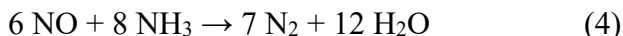
SCR is a post-combustion emission control process which involves removal of NO_x in a catalytic reactor. In the SCR process, ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water. The SCR process converts nitrogen oxides to nitrogen and water by the following chemical reactions:



⁷ 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.

⁸ U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031.

⁹ *Id.*



A catalyst is required to lower the activation energy at which NO_x 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.

SCR is capable of NO_x reduction efficiencies in the range of 70 to 90%. For most SCR catalyst configurations, the optimum operating temperature of the system is between 700 and 850°F.

Elimination of Technically Infeasible NO_x Control Options – CC Units (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 CC 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 may be 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 CC units is too low 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 CC 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 CC 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 (Bartow) in which The Plant is proposing to construct and operate the proposed CC units. This emission standard will limit NO_x emissions from the proposed CC units to less than 6 ppmvd, corrected to 15% O₂, based on a 30-operating day rolling average.

Summary and Ranking of Remaining NO_x Controls – CC Units (Step 3)

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

Evaluation of Most Stringent NO_x Controls – CC Units (Step 4)

The top control options are being proposed for NO_x emissions from the proposed CC 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)

Under NSPS Subpart KKKK, new, large combustion turbines such as the proposed CC units are subject to NO_x emission standards of 15 ppmvd while firing natural gas, 42 ppmvd while firing distillate oil, and 96 ppmvd when operating at part-load while firing either fuel.^{10, 11} Additionally, as discussed above, the proposed CC units will also be subject Georgia Rule (nnn), which will limit NO_x emissions from the proposed CC units to less than 6 ppmvd, corrected to 15% O₂, based on a 30-operating day rolling average while firing either fuel.

Based on the Plant review, NO_x BACT for the proposed CC units should be based on the use of DLN combustors, water injection, and SCR. In addition to the information provided in Appendix E, Tables E-1 through E-4, Figure 5-1 and Figure 5-2 of the application provide a graphical representation of the RBLC, NEEDS, and EIA-860 search results for gas-fired and distillate oil-fired CC units, respectively.

These results indicate that NO_x emission limits for CC units with similar controls range from 2 to 96 ppmvd while firing natural gas and from 4 to 96 ppmvd while firing distillate oil (only emission limits up to 10 ppmvd are shown in the Figures). The Plant proposes the following as NO_x BACT for each of the proposed CC units:

- 2.0 ppmvd NO_x or less when firing natural gas, based on a 4-hour rolling average, excluding periods of startup, shutdown, or fuel switching,

¹⁰ 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% O₂.

¹¹ The proposed NSPS Subpart KKKKa may lower the standards for new, large, non-peaking combustion turbines to 3 ppmvd while firing gas and 5 ppmvd while firing distillate oil.

- 5.0 ppmvd NO_x or less when firing distillate oil, based on a 4-hour rolling average, excluding periods of startup, shutdown, or fuel switching, and
- 203.7 tons NO_x or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

For natural gas, The Plant is proposing the level of control equivalent to the most stringent emission limit achieved in practice. This level of control is the same as Plant Barry Unit 8 (AL-0328) and Jackson Energy Center (JEC) Units 1 and 2 (IL-0130), which are the most similar CC units in commercial operation in the U.S., except that those units are gas-fired only and are not capable of firing distillate oil as a backup fuel.¹²

RBLC listed five facilities that have CC units for which permits were issued with an emission limit of 4 ppmvd when firing distillate oil: Killingly Energy Center (CT-0161), Sewaren Generating Station (NJ-0081), Middlesex Energy Center (NJ-0085), Cogen Tech Lingen Venture LP (NJ-0088), and Renovo Energy Center (PA-0334). Notably, only one of these five facilities, Sewaren Unit 7, has been constructed.¹³ Sewaren Unit 7 is a second-generation General Electric (GE) H-class unit (GE 7HA.02) and has approximately 30% lower NO_x emissions in the CT exhaust (and inlet to the SCR) compared to the proposed CC units, due to their lower firing temperature. To account for this significant difference between Sewaren Unit 7 and the Project, The Plant is proposing 5 ppmvd as NO_x BACT when firing distillate oil, which is a level of control consistent with proposed NSPS Subpart KKKKa.

Compliance with the NO_x BACT emission limits will be determined by CEMS. Similar to other CC units permitted by EPD, The Plant is proposing short-term emissions limits that exclude emissions during certain periods of operation, coupled with a mass cap that includes all valid emissions measured. For purposes of the proposed short-term NO_x BACT emission limits above, the following definitions apply:

Startup means the period of time from when the combustion turbine 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 288 minutes for a cold startup, 212 minutes for a warm startup, and 131 minutes for a hot startup while firing natural gas and 315 minutes for a cold startup, 232 minutes for a warm startup, and 145 minutes for a hot startup while firing distillate oil.

¹² Unit 1 at PowerSouth Cooperative's Charles R. Lowman Power Plant is also similar to the proposed CC units and in commercial operation but was not subject to PSD. Other similar units may be in commercial operation but operate in a different configuration (e.g., 2-on-1 or 3-on-1 combined-cycle configuration). Several permits have been issued to construct similar 1-on-1 CC units, but these projects were either canceled (Chickahominy Power (VA-0332)) or the applicant ultimately installed a different CT technology (e.g., Long Ridge Energy Station (OH-0375) and NTE Ohio (OH-0363)).

¹³ Both Middlesex Energy Center and Renovo Energy Center were issued permits for, but never constructed, CC units based on the GE 7HA.02 and Siemens SGCT-8000H CT technologies, while those at Killingly Energy Center and Cogen Tech Lingen Venture LP would have been based on the Mitsubishi 501GAC and GE 7FA.05 CT technologies. NO_x emissions in the CT exhaust (and inlet to the SCR) for all these CT technologies are at least 30% lower compared to the proposed CC units.

Cold startup means a startup to combined-cycle operation following a complete shutdown lasting more than 72 hours.

Warm startup means a startup to combined-cycle operation following a complete shutdown lasting 8 hours or more, but less than or equal to 72 hours.

Hot startup means a startup to combined-cycle operation following a complete shutdown lasting less than 8 hours.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 60 minutes.

Fuel switching means the period of time needed to change fuels during load operation without a complete shutdown, not to exceed 80 minutes.

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 – CC Units NO_x Control

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

- USEPA RACT/BACT/LAER Clearinghouse¹⁴
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM₁₀, CO, Greenhouse Gases, H₂SO₄ and VOC BACT analyses.

After reviewing the RBLC Database, the Division has verified that the majority of the BACT controls on the combined cycle turbines have the use of DLN combustors, water injection, and SCR. Also, the limits of 2 ppmvd at 15% O₂ for natural gas combustion and 4 ppmvd at 15% O₂ for distillate oil combustion are common limits in the RBLC database, although the Plant's proposal of 5 ppmvd at 15% O₂ as a NO_x BACT limit when firing distillate oil due to their higher firing temperature is acceptable. The RBLC data has been examined for the last ten years for combined cycle combustion turbines.

¹⁴ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

Conclusion – CC Units NOx Control

The technically feasible control technologies for NOx emission control for combined 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 BACT 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, and dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation for NOx control in the CC Units.

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 203.7 tons of NOx emissions (12 consecutive month average) firing natural gas or fuel oil** from each of the CC Units (Source Codes: CT7/DB7-CT10/DB10).

The BACT selection for the CC Units (Source Codes: CT7/DB7-CT10/DB10) is summarized below in Table 4-1:

Table 4-1: BACT Summary for the CC Units (Source Codes: CT7/DB7-CT10/DB10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Dry Low NOx Burners (firing Natural Gas)	2.0 ppmvd @ 15% O ₂ 5 ppmvd @ 15% O ₂	4 hours	NOx CEMS
	Water Injection (firing Fuel Oil)			
	Clean/Low-Emitting Fuels			
	SCR			
NOx	Dry Low NOx Burners (firing Natural Gas)	203.7 tons*	12 consecutive months	NOx CEMS
	Water Injection (firing Fuel Oil)			
	Clean/Low-Emitting Fuels			
	SCR			

*Limit includes emissions during startup and shutdown.

Combined Cycle (Source Codes: CT7/DB7 - CT10/DB10) – SO₂ 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 SO₂ 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 SO₂.

SO₂ Formation – CC Units

Emissions of SO₂ occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO₂ emissions associated with combustion of natural gas and distillate oil are typically very low due to the low concentration of sulfur compounds in the fuel.

Identification of SO₂ Control Technologies – CC Units (Step 1)

The Plant reviewed SO₂ BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS as having commenced commercial operation in 2019 and after or listed as planned and under construction in EIA-860. The results of these searches are summarized in Appendix E of the application, Tables E-5 through E-8. Based on this review, no add-on controls were identified. All these listings describe the use of natural gas or other fuel with inherently low sulfur content as BACT. Some of these listings also identify efficient combustion or good combustion practices as BACT.

Flue gas desulfurization (FGD) is a post-combustion add-on control option that has been used to control SO₂ emissions from certain combustion sources that fire high sulfur-content fuels, including coal-fired and residual oil-fired boilers. However, when emission standards for combustion turbines were initially proposed under the NSPS program, EPA concluded that use of FGD on these units would be unreasonable based on cost.¹⁵ Instead, low sulfur fuels were chosen as the basis for the standards. Similarly, the use of low sulfur fuel is the basis of the SO₂ emission standard in NSPS Subpart KKKK.¹⁶ EPA has proposed to maintain these standards without changes in proposed NSPS Subpart KKKKa.¹⁷ Notably, in the NSPS Subpart KKKKa proposal, EPA refers to FGD as “not an applicable alternative for the control of SO₂ emissions” and does not reference the unreasonable cost of control. Accordingly, use of fuels with inherently low sulfur content is the only potentially available control option for SO₂ emissions from the proposed CC units.

¹⁵ 42 Fed. Reg. at 53782, 53785 (October 3, 1977).

¹⁶ 70 Fed. Reg. at 8314, 8320 (February 18, 2005).

¹⁷ 89 Fed. Reg. at 101306, 101342 (December 13, 2024). In the NSPS Subpart KKKKa proposal,

Elimination of Technically Infeasible SO₂ Control Options – CC Units (Step 2)

Use of fuels with inherently low sulfur content, such as natural gas and distillate oil, is inherent to the Project and technically feasible.

Summary and Ranking of Remaining SO₂ Controls – CC Units (Step 3)

No ranking of control options is required, as use of fuels with inherently low sulfur content is the only available and technically feasible control option for SO₂ emissions from the proposed CC units.

Evaluation of Most Stringent SO₂ Controls – CC Units (Step 4)

The top control option is being proposed for SO₂ emissions from the proposed CC units. Therefore, no further evaluation of the impacts of the control options is required.

Selection of Emission Limits for SO₂ BACT (Step 5)

Based on The Plant's review, SO₂ BACT for the proposed CC units should be based on the use of fuels with inherently low sulfur content. Therefore, The Plant proposes the exclusive use of natural gas that meets the definition of pipeline quality natural gas as defined in 40 CFR 72.2 and distillate oil with a sulfur content less than 15 ppm, by weight, as SO₂ BACT for the proposed CC units. The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

EPD Review – CC Units SO₂ Control

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 SO₂ BACT comparison spreadsheet for the similar units using the resources, as discussed in the NO_x BACT review.

GA EPD agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for SO₂.

Conclusion – CC Units SO₂ Control

The technically feasible control technologies for SO₂ emission control for simple cycle turbines are clean fuels. Therefore, clean fuels are the demonstrated and technically feasible options to be considered for this project.

The Division agrees with the facility's proposed use of clean fuels as BACT.

The BACT selection for the CC Units (Source Codes CT7/DB7-CT10/DB10) is summarized below in Table 4-2:

Table 4-2: BACT Summary for the CC Units (Source Codes CT7/DB10-CT10/DB10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO ₂	Low Sulfur Content Fuels (Natural Gas, ULSD)	Natural gas, 0.5 grains sulfur/100 scf Ultra-low sulfur distillate oil (15 ppm sulfur)	N/A	Recordkeeping

Combined Cycle (Source Codes: CT7/DB7 - CT10/DB10) – 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 – CC Units

CO emissions from the proposed CC units may be generated during combustion as a result of incomplete conversion of carbon-containing compounds to CO₂ and water. CO emission rates are principally influenced by equipment operating conditions; elevated CO emissions may be the result of low combustion temperature, insufficient combustor residence time, and/or low operating loads.

Identification of CO Control Technologies – CC Units (Step 1)

The Plant reviewed CO BACT determinations found in the RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS as having commenced commercial operation in 2019 and after or listed as planned and under construction in EIA-860. The results of these searches are summarized in Appendix E of the application, Tables E-9 through E-12.¹⁸ Potentially available control options to reduce CO emissions from the proposed CC units include combustion controls, good combustion practices, and post-combustion add-on controls such as an oxidation catalyst. Each is 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 CC units.

Oxidation Catalyst

An oxidation catalyst is a passive control option that uses excess air to convert CO emissions to CO₂ in the presence of catalyst without the injection of a reagent. An oxidation catalyst is a passive control option that uses excess air to convert CO emissions to CO₂ in the presence of catalyst without injection 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.

¹⁸ Many CC units have different CO (and VOC) emission limits applicable to periods of time when the duct burner(s) are in service and are listed separately, as applicable.

Elimination of Technically Infeasible CO Control Options – CC Units (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 CT MACT (40 CFR 63 Subpart YYYYY).

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

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

Evaluation of Most Stringent CO Controls – CC Units (Step 4)

The top control options are being proposed for CO emissions from the proposed CC 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)

Based on The Plant review, CO BACT for the proposed CC units should be based on use of clean fuels, good combustion practices, and an oxidation catalyst. In addition to the information provided in Appendix E of the application, Tables E-9 through E-12, Figure 5-3 and Figure 5-4 of the application provide a graphical representation of the RBLC, NEEDS, and EIA-860 search results for natural gas-fired and distillate oil-fired CC units, respectively.

These results indicate CO emission limits for CC units with similar controls vary considerably and are as low as 0.9 ppmvd while firing natural gas and as low as 1.8 ppmvd while firing distillate oil (only emission limits up to 10 ppmvd are shown in the Figures). In many cases, the level of control depends on fuel, load, and whether duct burners are in-service (to account for supplemental firing in the HRSG). For both fuels, most emissions limits are 2 ppmvd.

The Plant proposes the following as CO BACT for each of the proposed CC units:

- 2.0 ppmvd CO or less when firing natural gas or distillate oil based on a 24-hour rolling average, excluding periods of startup, shutdown, or fuel switching and
- 257.4 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

For both gas and distillate oil, The Plant is proposing 2 ppm as CO BACT, a level of control consistent with the majority of CO emission limits found for CC units. This level of control is also the same as Plant Barry Unit 8 (AL-0328) and JEC Units 1 and 2 (IL-0130) and therefore reflects the most stringent emission limit achieved in practice for similar CC units in commercial operation in the US. In most cases, permits issued to CC units with CO emissions limits that are more

stringent than 2 ppmvd are associated with projects that were cancelled and never built, including Palmdale Energy Project (CA-1251), Killingly Energy Center (CT-0161), Chickahominy Power (VA-0332), ESC Tioga County Power (PA-0333), Renovo Energy Center (PA-0334), and Nemadji Trail Energy Center (WI-0300). In all but one of these cases (Chickahominy), the applicant proposed to construct a previous generation CT with inherently lower CO emissions in the CT exhaust (and inlet to the oxidation catalyst) relative to the proposed CC units. In the case of Chickahominy, while the CT technology would have been similar were it constructed, the applicant did not propose supplemental firing, i.e., duct burners, in the HRSG. Since an oxidation catalyst is a passive control that does not include injection of a reagent or other means to actively control emissions, CO BACT for the proposed CC units is necessarily higher to account for these differences.

Compliance with the CO BACT emission limits will be determined by CEMS. Of the two most similar CC units that have achieved a level of control of 2 ppmvd in practice, only JEC Units 1 and 2 use CO CEMS for compliance. The Plant notes that JEC's permit includes alternate CO limits that apply during low load operations, which are not included in the RBLC information.¹⁹ As discussed above, CO emissions performance is highly sensitive to combustion temperature, which can be impacted by many factors, including operating load and ramp rate (i.e., the rate at which operating load changes). JEC's alternate CO limits effectively allow emissions in excess of 2 ppmvd as long as the equivalent average mass emission rate (i.e., lb/hr) does not increase. The Plant agrees that it is important for CO BACT to account for temporary peaks in emissions that may occur during periods of operation at low load and sudden changes in load. However, instead of layering in additional emissions limitations, The Plant proposes that compliance with CO BACT be demonstrated on a 24-hour rolling average.

Similar to other CC units permitted by EPD, The Plant is proposing short-term emissions limits that exclude emissions during certain periods of operation, coupled with a mass cap that includes all valid emissions measured. For purposes of the proposed short-term CO BACT emission limits above, the following definitions apply:

Startup means the period of time from when the combustion turbine 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 288 minutes for a cold startup, 212 minutes for a warm startup, and 131 minutes for a hot startup while firing natural gas and 315 minutes for a cold startup, 232 minutes for a warm startup, and 145 minutes for a hot startup while firing distillate oil.

Cold startup means a startup to combined-cycle operation following a complete shutdown lasting more than 72 hours.

¹⁹ Jackson Energy Center, I.D. No.: 197035ABD, Application No. 17040013, dated April 4, 2017, Construction Permit – PSD Approval, dated December 31, 2018. See Section 2.1.2.c.i for CO BACT and Section 2.1.6.a.iii for the alternate limits during periods of low load operation. The Plant notes that the permit does not restrict or limit the amount of time JEC Units 1 and 2 may operate under the alternate limits.

Warm startup means a startup to combined-cycle operation following a complete shutdown lasting 8 hours or more, but less than or equal to 72 hours.

Hot startup means a startup to combined-cycle operation following a complete shutdown lasting less than 8 hours.

Shutdown means the period of time from MECL to when firing of fuel has ceased, not to exceed 60 minutes.

Fuel switching means the period of time needed to change fuels during load operation without a complete shutdown, not to exceed 80 minutes.

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.

EPD Review – CO CC Units Control

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 NO_x 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 257.4 tons during any 12 consecutive months, and 2.0 ppmvd (NG or FO).

Conclusion – CO CC Units Control

The technically feasible control technologies for CO emission control for combined 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 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 257.4 tons of CO emissions (12 consecutive month average) firing natural gas or fuel oil** from each of the CC Units (Source Codes: CT7/DB7-CT10/DB10).

The BACT selection for the CC Units (Source Codes CT7/DB7-CT10/DB10) is summarized below in Table 4-3:

Table 4-3: BACT Summary for the CC Units (Source Codes CT7/DB7-CT10/DB10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices Clean/Low-Emitting Fuels Oxidation Catalyst	2.0 ppmvd @ 15% O ₂ (NG or FO)	4 hours	CO CEMS
CO	Good Combustion Practices Clean/Low-Emitting Fuels Oxidation Catalyst	257.4 tons*	12 consecutive months	CO CEMS

Combined Cycle (Source Codes: CT7/DB7 - CT10/DB10) – 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 – CC Units

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

Identification of VOC Control Technologies – CC Units (Step 1)

The Plant reviewed VOC BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS as having commenced commercial operation in 2019 and after or listed as planned and under construction in EIA-860. The results of these searches are summarized in Appendix E of the application, Tables E-13 through E-16.²⁰ Potentially available control options for VOC emissions from the proposed CC 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.

Elimination of Technically Infeasible VOC Control Options – CC Units (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 CT MACT (40 CFR 63 Subpart YYYY).

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

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

Evaluation of Most Stringent VOC Controls – CC Units (Step 4)

The top control options are being proposed for VOC emissions from the proposed CC units. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

²⁰ See footnote 18.

Selection of Emission Limits for VOC BACT (Step 5)

Based on the Plant review, VOC BACT for the proposed CC units should be based on use of clean/low-emitting fuels, good combustion practices, and an oxidation catalyst. In addition to the information provided in Appendix E of the application, Tables E-13 through E-16, Figure 5-5 and Figure 5-6 of the application provide a graphical representation of the RBLC, NEEDS, and EIA-860 search results for natural gas-fired and distillate oil-fired CC units, respectively.

These results indicate VOC emission limits for CC units with similar controls vary considerably and are as low as 0.33 ppmvd (as propane) while firing natural gas and as low as 1.9 ppmvd while firing distillate oil (only emission limits up to 8 ppmvd are shown in the Figures). In many cases, the level of control depends on fuel, load, and whether duct burners are in-service (to account for supplemental firing in the HRSG). For both fuels, most emissions limits are 2 ppmvd.

The Plant proposes the following as VOC BACT for each of the proposed CC units:

- 1.0 ppmvd VOC, as methane, or less when firing natural gas without the duct burners in-service based on the average of a 3-run stack test using EPA Reference Method 25A.
- 2.0 ppmvd VOC, as methane, or less when firing distillate oil with the duct burners in-service based on the average of a 3-run stack test using EPA Reference Method 25A switching.

For gas when the duct burners are not in-service, the Plant is proposing 1 ppmvd, as methane, as VOC BACT, a level of control consistent with the majority of VOC emission limits found for CC units and the same as JEC Units 1 and 2 (IL-0130). Similar to CO, permits issued to CC units with VOC emissions limits that are more stringent than 1 ppmvd are associated with projects that were cancelled and never built, including Killingly Energy Center (CT-0161), Rolling Hills Generating, LLC (OH-0365), C4GT, LLC (VA-0328), Chickahominy Power (VA-0332), and Nemadji Trail Energy Center (WI-0300). Other facilities, such as West Deptford Energy Station (NJ-0082) and Greenville Power Station (VA-0325), are based on a smaller or previous generation of CT technology with inherently lower emissions. And, Birdsboro Power (NEEDS), which appears to have the most stringent VOC limit at 0.33 ppmvd as propane, is equivalent to the proposed VOC BACT when converted to an as-methane basis.

For gas when the duct burners are in-service, and for distillate oil, the Plant is proposing 2 ppmvd, as methane, as VOC BACT, which is also consistent with majority of VOC emission limits found for CC units and the same as Plant Barry Unit 8 (AL-0328) and JEC Units 1 and 2 (IL-0130).

The Plant proposes to conduct a stack test after initial startup followed by subsequent stack tests every five years. Compliance with the VOC BACT emission limits for the proposed CC units will be assured as long as the CO emissions are in compliance with the corresponding CO BACT emission limits.

EPD Review – CC Units (Source Codes CT7/DB7-CT10/Db10) 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 84 Facility VOC BACT limits, 41 facilities (48.8 %) 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 – CC Units (Source Codes CT7/DB7-CT10/DB10) VOC Control

The technically feasible control technologies for VOC emission control for combined 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 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 CC Units (Source Codes CT7/DB7-CT10/DB10) is summarized below in Table 4-4:

Table 4-4: BACT Summary for the Combustion Turbines (Source Codes CT7-CT10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Practices Clean Fuels/Low-Emitting Oxidation Catalyst	1.0 ppmvd or less, as methane, @ 15% O ₂ (NG) <u>without</u> the Duct Burners in service 2.0 ppmvd as methane, @ 15% O ₂ when firing natural gas <u>with</u> the Duct Burners in service or	N/A	3-run stack test EPA Reference Method 25A

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
		when firing distillate oil		

CC Units (Source Codes: CT7/DB7-CT10/DB10) – Particulate Matter, Particulate Matter Less than 10 Microns (PM₁₀), 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 combined-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 PM₁₀/PM_{2.5}.

PM Formation – CC Units

PM emissions from the proposed CT units include both filterable and condensable particles.²¹ 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 – CC Units (Step 1)

For PM, The Plant also reviewed BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS or EIA-860. The results of these RBLC searches are summarized in Appendix E of application, Tables E-17 through E-20.

Based on this review, no add-on control options were identified. Instead, many facilities listed some variation of use of fuels with inherently low sulfur content and good combustion practices as BACT. Generally, conventional add-on controls, such as baghouses and electrostatic precipitators, often applied to solid fuel boilers, have not been applied to combustion turbines.²²

With the BACT context, these emission controls have no *practical potential* to reduce emissions from the proposed CC units because the use of clean fuels inherently results in a low level of PM

²¹ For the purposes of BACT, emission limits for PM include only filterable PM, while emission limits for PM₁₀ and PM_{2.5} are required to include both filterable and condensable fractions. In this BACT analysis, when The Plant uses the term “PM,” it is meant to include both PM₁₀ and PM_{2.5} unless otherwise noted.

²² 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. 44 Fed. Reg. at 52792 and 52798 (Sept. 10, 1979); EPA, *Standards Support and Env'tl. Impact Statement Volume 1: Proposed Standards of Performance for Stationary Gas Turbines*, at 8-6 (Sept. 1977). Additionally, when EPA proposed to update the standards in NSPS Subpart KKKK, EPA declined to establish standards for PM because “[PM] emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the lower ash content...” 70 Fed. Reg. at 8314 and 8321 (Feb. 18, 2005). At the time, EPA also noted that no CT units permitted since 2003 utilized add-on controls.

emissions. For example, the outlet performance specification of a typical baghouse or electrostatic precipitator is 0.01 gr/dscf.²³ Based on information provided in Appendix C of the application, the total concentration of PM emissions, including condensables, from the proposed CC units is expected to range from approximately 0.002 to 0.004 gr/dscf, depending on the fuel being utilized, which is nearly an order of magnitude lower than what these control options typically achieve. Accordingly, these controls need not be listed in Step 1 of the BACT analysis. However, even if listed in Step 1, these control options would be eliminated as technically infeasible in Step 2 for essentially the same reason—they have no real potential to reduce PM emissions from the proposed CC units.²⁴ Therefore, only the use of fuels with inherently low sulfur content and good combustion practices are considered further.

Elimination of Technically Infeasible PM Control Options – CC Units (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 – CC Units (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 CC units.

Evaluation of Most Stringent PM Controls – CC Units (Step 4)

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

Selection of Emission Limits for PM BACT (Step 5)

Based on the Plant's review, PM BACT for the proposed CC units should be based on use of fuels with inherently low sulfur content and good combustion practices. The Plant proposes the following as PM BACT for each of the proposed CC units:

- Total PM, containing filterable and condensable PM, equal to or less than 0.0045 lb/MMBtu, when firing natural gas, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202; and
- Total PM, containing filterable and condensable PM, equal to or less than 0.0135 lb/MMBtu, when firing distillate oil, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202.

²³ See North Carolina Division of Air Quality, Application Review for Siemens Energy test facility at Duke LCTS, Application No. 5500082.17A, at 31 (June 20, 2018).

²⁴ See, for example, Washington County Power, LLC, Application No. TV-547905, Volume I – Construction Permit Application, Section 5.7 (February 25, 2021), and related PSD Preliminary Determination (September 10, 2021). Available at <https://epd.georgia.gov/document/document/tv-547905-narrative-revised/download>.

The proposed PM BACT reflects approximately 0.002 lb/MMBtu filterable PM when firing gas, 0.01 lb/MMBtu when firing distillate oil, and full conversion of the sulfur in fuel to inorganic sulfate-based condensables. In establishing BACT, full conversion of sulfur to sulfates is appropriate since vendors do not offer guarantees to limit sulfur conversion to SO₃ in the CT and HRSG and there are sufficient amounts of moisture and ammonia in the exhaust to complete sulfate formation, even at extremely low levels of ammonia slip (<0.3 ppmvd).

In addition to the information provided in Appendix E of the application, Tables E-17 through E-20, Figure 5-7 and Figure 5-8 provide a graphical representation of the RBLC, NEEDS, and EIA-860 search results for natural gas-fired and distillate oil-fired CC units, respectively. These results indicate total PM emission limits for CC units with similar controls are as low as 0.0024 lb/MMBtu while firing natural gas and as low as 0.0122 lb/MMBtu while firing distillate oil.

However, after additional research, the Plant notes that many of the PM emissions limits found for CC units that are lower than the proposed BACT: (1) are not total PM, but filterable only and do not include condensables, such as JEC (IL-0130), Lincoln Energy Center (IL-0133), and Thomas Township Energy (MI 0442); (2) are not total PM, but are total PM₁₀ and PM_{2.5} and use EPA Method 201A to measure filterable particle size fractions with a cyclone, such as Long Ridge Energy Generation (OH-0375); or (3) are based on different assumptions that impact estimation of inorganic condensable PM from fuel sulfur content, such as Panda Stonewall (VA-0335).²⁵

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 (PM₁₀), 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/PM₁₀/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/PM₁₀/PM_{2.5}.

²⁵ For Panda Stonewall, the maximum sulfur content of the natural gas allowed to be fired in the CC units is 0.1 grains per 100 standard cubic feet. Permit available at <https://energy.virginia.gov/renewableenergy/documents/RetirementFossilFuels/StonewallPermit.pdf>.

Conclusion – CC Units (Source Codes CT7/DB7-CT10/DB10) Particulate Matter, Particulate Matter Less than 10 Microns (PM₁₀), and Particulate Matter Less than 2.5 Microns (PM_{2.5}) Control

The BACT selection for the CC Units (Source Codes CT7/DB7-CT10/DB10) is summarized below in Table 4-5:

Table 4-5: BACT Summary for the CC Units (Source Codes CT7/DB7-CT10/DB10)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Low Sulfur Content Fuels	0.0045 lb/MMBTU (NG) 0.0135 lb/MMBTU (FO)	N/A	3-run stack test EPA Reference Methods 5, and/or 202, as applicable

CC Units (Source Codes: CT7/DB7-CT10/DB10) – Sulfuric Acid Mist (SAM) EmissionsApplicant's ProposalSAM Formation – CC Units

Sulfuric acid mist (SAM), or H_2SO_4 , emissions from the proposed CC 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 – CC Units (Step 1)

The only potentially available control option for SAM emissions from the proposed CC 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 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 – CC Units (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 – CC Units (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 CC units.

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

The top control option is being proposed for SAM emissions from the proposed CC 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 CC units since EPA does not regulate this pollutant under NSPS Subpart KKKK.

SAM BACT for the proposed CC 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 CC 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 – CC Units 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.

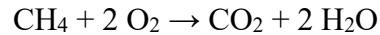
The BACT selection for the Combustion Turbines is summarized below in Table 4-6:

Table 4-6: BACT Summary for the CC Units

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

CC Units (Source Codes: CT7/DB7-CT10/DB10) – Greenhouse Gases – CO₂ EmissionsApplicant's ProposalGreenhouse Gases – CO₂ Formation – CC Units

GHG emissions that result from the combustion of clean fuels in the proposed CC units include CO₂, CH₄, and N₂O. CO₂ is a necessary product of combustion from fuels containing carbon. For example, the theoretical combustion equation for CH₄, the primary component of natural gas, is:



Consequently, CO₂ 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 – CO₂ Control Technologies – CC Units (Step 1)

As with the other BACT reviews above, the Plant reviewed CO₂ BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and also reviewed permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS and EIA-860. Based on these search results, no add-on control options were identified in RBLC or in any permit or application. However, many facilities listed inherently lower-emitting processes and practices as BACT, including some variation of use of clean or lower-emitting fuels, efficient design, and good combustion practices as BACT for CO₂ emissions. These results are summarized in Appendix E of the application, Tables E-23 and E-24.

The Plant also considered relevant federal and state emission standards and relied on Southern Company's experience as a leader in low-carbon technology research and innovation to identify additional potential control options for CO₂ emissions from the proposed CC units. EPA's 2023 proposed GHG emissions standards identified co-firing low GHG-hydrogen as a potential control option,²⁶ although this control option was not included in the final regulations adopted in Subpart TTTTa.²⁷ EPA's final emission GHG standards in Subpart TTTTa, which are potentially applicable to the Project, identify carbon capture and storage (CCS) as a potential control option. No additional control options were identified based on Southern Company's low-carbon technology research activities.

This analysis assesses each of the control options identified above in further detail below. This BACT analysis does not consider processes or designs that would fundamentally redefine the proposed source, such as solar, battery energy storage systems (BESS), or BESS plus solar.²⁸

²⁶ 88 Fed. Reg. at 33284 (May 23, 2023).

²⁷ 40 CFR Part 60, Subpart TTTTa.

²⁸ See U.S. EPA, *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); Memorandum from Stephen Page, Director, Office of Air Quality, Planning, and Standards, U.S. EPA, to Paul Plath, re: *Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects* (Dec. 13, 2005); *In re Prairie State*

Use of Clean/Lower-Emitting Fuels

RBLC and permit review identifies clean fuels as a control option. In addition, EPA identified the use of fuels such as natural gas and distillate oil as an available control option in both the 2015 and 2024 111 GHG Rules. These fuels are referred to variously as “clean fuels” in Subpart TTTT and as “lower-emitting fuels” in Subpart TTTTa.

Efficient Design

The RBLC identified efficient design as a control option for combined units.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices is identified as control options in the RBLC.

Use of Low-GHG Hydrogen

In its 2023 proposed GHG emissions standards, 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 hydrogen through use of a low CO₂ emission technology, such as a renewable energy-powered process or a fossil fuel-powered process paired with CCS. Notably, co-firing low-GHG hydrogen was not included in the final standards due to significant uncertainties related to the availability and cost-effectiveness of this control option.²⁹ Co-firing low-GHG hydrogen is nonetheless evaluated as a potential control option in this BACT analysis based on its inclusion in the proposal.

Carbon Capture and Storage

While EPA removed co-firing low-GHG hydrogen from the final rules in Subpart TTTTa, it did base the final standards for some CT units, in part, on CCS. Therefore, CCS is evaluated as a potential control option in this BACT analysis. CCS requires the integration of a variety of processes and equipment to separate and capture CO₂ from the exhaust stream, compress and transport the CO₂ to a suitable geologic storage location and pump the CO₂ deep underground. Notably, EPA’s determination in Subpart TTTTa that CCS is BSER for some combustion turbines is the subject of litigation currently underway in the U.S. Circuit Court of Appeals for the D.C. Circuit,³⁰ and EPA has also proposed to repeal the CCS requirements in Subpart TTTTa.³¹

Generating Company, 13 E.A.D. 1, 23 (EAB 2006); US EPA PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011).

²⁹ 89 Fed. Reg. at 39939 (May 9, 2024).

³⁰ *West Virginia v. EPA*, No. 24-1120.

³¹ 90 Fed. Reg. 25752 (June 17, 2025).

Based on the discussion above, the following potential control options for CO₂ emissions from the proposed CC units were considered as part of this BACT analysis:

- Use of clean/low-emitting 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 storage (CCS).

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

Elimination of Technically Infeasible Greenhouse Gases – CO₂ Control Technologies – CC Units (Step 2)

Use of Clean Fuels

Use of clean/low-emitting fuels (natural gas and distillate oil) is inherent to the Project. Accordingly, use of clean/lower emitting fuels, is available, applicable to the Project, and thus technically feasible.

Use of Efficient Design

Use of efficient design is inherent to the Project. Combined-cycle units are highly efficient thermal units since these units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A CT operates on the Brayton cycle, and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with CC units.

The CT technology that will be used for the Project represents the next evolution in efficiency 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. These design elements make the CT technology among the most efficient available. 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.

Waste heat recovery in the HRSG also represents efficient design. These heat exchangers are designed to capture thermal energy from CT exhaust gases and duct burners, using this heat to convert water into steam to drive a steam turbine, and increase power generation and overall

efficiency. One aspect of the HRSG design to maximize waste heat recovery is the use of insulation on all gas path surfaces exposed to ambient air. Insulation minimizes heat loss to the ambient air, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high temperature steam and water lines, and typically to the bottom portion of the stack.

Based on the above, use of efficient design is available, applicable to the Project, and thus technically feasible.

Use of Good Combustion, Operating, and Maintenance Practices

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

The proposed CT units will also be maintained following a maintenance program recommended 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 as much lost performance as possible.

HRSG maintenance is also important. HRSGs are made up of tubes within the shell of the unit that are used to generate steam from the heat in the CT exhaust gas. To maximize heat transfer, the tubes and their extended surfaces need to be cleaned regularly. Although filtration of the inlet air to the CT reduces contaminants thereby minimizing fouling of the tubes, cleaning of the tubes is also performed during periodic outages. By minimizing fouling, the heat transfer efficiency of the HRSG tubes is maximized. Based on the above, use of good combustion, maintenance, and operating practices is available, applicable to the Project, and thus 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.

With respect to availability, low-GHG hydrogen is not commercially available, since it is not produced in sufficient quantities in the U.S. and cannot be obtained through any known commercial channels in the vicinity of the Project. While the 2021 Infrastructure Investment and Jobs Act (IIJA) and the 2022 Inflation Reduction Act (IRA) provide funding opportunities and tax credits aimed at driving down the cost of production, processing, delivery, and storage of low-GHG hydrogen, these incentives are not projected 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.³² Additionally, the US Treasury has only recently released rules 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.³³ GPC is unaware of any plans to build out the significant infrastructure necessary to make low-GHG hydrogen a commercially available control option. Even if sufficient supply were available, there are insufficient pipelines to transport low-GHG hydrogen to customers since pipeline gas quality specifications, in particular higher heating value (HHV), prevent blending the volumes of hydrogen that would be required into the existing natural gas infrastructure.³⁴ Thus, low-GHG hydrogen is not an available control option, and therefore cannot be an applicable control option for the CC units.

According to EPA guidance, applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations."³⁵ Since hydrogen co-firing has not been demonstrated in practice, it does not constitute a demonstrated and applicable control technology for the proposed CC units. Accordingly, low-GHG hydrogen is not technically feasible.

Carbon Capture and Storage

CCS is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO₂ from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for permanent storage. To date, CCS has not been demonstrated at full scale in practice on a combustion turbine. For CCS to be technically feasible, each individual step in the process—capture and compression, transportation,

³² <https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations>.

³³ 90 Fed. Reg. 2224 (January 10, 2025).

³⁴ 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). For example, 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.

³⁵ U.S. EPA, *Draft New Source Review Workshop Manual*, at B.11 (Oct. 1990).

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.³⁶ Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

Capture and Compression

There are two CCS systems currently installed and operational at commercial power plants in North America: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova project in Texas. However, both of these projects are coal-fired steam units, both are comparatively small, and both have experienced significant technical and operational hurdles that have prevented continuous successful operation, as would be required for a typical power plant. Boundary Dam is a 110 MW coal-fired unit that was designed for but has proven incapable of capturing up to 90 percent of its CO₂ emissions using an amine solvent. While Boundary Dam has captured over six million metric tons of CO₂ since carbon capture operations began in 2014, this represents less than 63% percent of the one million tons per year goal, or a carbon capture rate of only 57%.³⁷ Furthermore, it has experienced ongoing equipment issues that have negatively impacted the unit's ability to consistently capture CO₂. Similarly, the Petra Nova project was designed to capture 90 percent of the CO₂ emissions of a 240 MW slip stream from a 610 MW coal-fired unit (approximately 35 percent of the unit's total CO₂ emissions) to be used for enhanced oil recovery. In its three years of operation, Petra Nova missed its carbon capture target by about 17 percent relative to what developers had expected and the project was discontinued in 2020 due to lack of economic viability, although Petra Nova recently restarted in the latter half of 2023. During the prior period of system operation, Petra Nova experienced outages on 367 days, with the CCS facility accounting for more than one-fourth of those outage days.³⁸ Additionally, the Petra Nova capture system was powered by a separate gas-fired combustion turbine, and the CO₂ emissions from the turbine were not captured, which materially reduced the actual net emissions reductions from the project.

Both the Boundary Dam and Petra Nova projects demonstrate the need for continued research efforts to not only reduce both capital and operational costs for CCS, but also to improve component design to maintain equipment reliability and performance, which are critical when facilities are required to consistently meet regulatory emission limits and when reliability of power generation must be considered.

In addition to the types of carbon capture technology employed at Boundary Dam and Petra Nova and being examined in FEED studies, there are other carbon capture technologies that are under development, such as polymeric membranes, combination solvent/membranes, and solid sorbents.

³⁶ U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 35-36 (March 2011).

³⁷<https://ieefa.org/resources/carbon-capture-boundary-dam-3-still-underperforming-failure>.

³⁸<https://www.reuters.com/article/business/environment/problems-plagued-us-co2-capture-project-before-shutdown/document-idUSKCN2523K7/>

Polymeric membranes have shown potential for carbon capture from coal-fired flue gas streams but are challenged by the lower CO₂ partial pressures/concentrations from CC units. Combination solvent/membrane systems are not yet ready for demonstration. Solid sorbents are likewise developing technologies but also not yet demonstrated at relevant scale.

While there has been significant progress made in the development of carbon capture systems for coal-fired steam electric generating units, carbon capture technology has not been adequately demonstrated at scale for simple- or combined-cycle combustion turbines. In CTs, whether in simple-cycle or combined-cycle configurations, a significant portion of the air drawn into the compressor is not used for combustion, but for cooling various internal components, including the combustor and turbine blades. This, coupled with the combustion of clean, or lower-emitting fuels such as natural gas or distillate oil, results in a dilute gas stream with inherently low concentrations of CO₂, making CO₂ separation, i.e., capture, more difficult compared to other combustion streams. For this reason alone, CCS was recently determined to be technically infeasible as BACT for a proposed, highly efficient CC unit, even when CCS was planned for other processes with high purity CO₂ gas streams at the same stationary source.³⁹

Technology testing at the National Carbon Capture Center (NCCC) and the Technology Centre Mongstad (TCM) (located in Mongstad, Norway), focused primarily on use of amine solvents, has been valuable to evaluate carbon capture technologies and move them through development to prepare for future potential demonstration.⁴⁰ Several technologies that have been tested at those facilities are now in the Front-End Engineering Design (FEED) stage, which refines the expected costs of those options. Nevertheless, a technology must be adequately demonstrated at a scale beyond the NCCC or TCM to identify and address operational issues before being considered commercially available. Many of these projects are now advancing and have been selected for

³⁹ Wabash Valley Resources (RBLD Id. IN-0371) plans to redevelop an existing coal gasification plant in West Terre Haute, Indiana (formerly the Duke Energy Wabash River Station) to make hydrogen for sale or use as feedstock in the production of anhydrous ammonia fertilizer. <https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-gasification-doe-fecm.pdf>. The developers plan to produce blue hydrogen by incorporating CCS downstream of the sweet gas water shift reaction, which would create a gas stream with high concentrations of CO₂ by reacting CO in the sweet gas with steam. The developers also plan to integrate a natural gas-fired CC unit to provide power and steam to the ammonia plant. The Indiana Department of Environmental Management (IDEM) found that CCS for the proposed CC unit was not technically feasible because it could not be reasonably installed and operated on the source under consideration. See Addendum to the Technical Support Document (ATSD) for Permit No. 167-45208-00091, dated January 11, 2024, Appendix B, CO₂e BACT Analysis – 2,292 MMBtu/hr IGCC CT.

⁴⁰ Southern Company, parent company to Georgia Power Company, manages and operates the National Carbon Capture Center (NCCC) located in Wilsonville, Alabama. The NCCC team leads world-class research of next-generation carbon capture technologies with approximately 150 highly specialized engineers, operations, maintenance, and support staff, and construction personnel taking projects through onboarding, design, scale-up, testing, data analysis, final evaluation, and demobilization. NCCC shares knowledge with developers and test facilities as technology is scaled up following testing at the NCCC.

follow-on pilot and demonstration projects,⁴¹ but commercial application of these projects will remain unproven for years. The Plant is aware of a permit been issued for CCS to the CC units located at CPV Basin Ranch Holding, Inc. in Ward, Texas, but this CCS system has not yet been constructed.⁴² The permit narrative makes clear that CCS was not determined to be BACT based on a top-down analysis and that CCS was not required by any other regulatory requirement; rather, the decision to install CCS was voluntary and intended by the applicant “to advance the technology for future development and commercialization as it relates to the power generation industry.”

Participating in these FEED studies has provided significant insight into the technical and logistical aspects of integrating CO₂ capture on a CC unit. Equally as important, these FEED studies have revealed and highlighted areas where more detailed work and experience is needed to understand the operating, maintenance, and reliability impacts of a CC unit with CCS on the electric grid, particularly with respect to non-steady state operating conditions. As recognized by Congress through the IJJA (Infrastructure Investment and Jobs Act) and subsequent DOE (Department of Energy) FOAs (Funding Opportunity Announcements), the next step in application of CCS on combustion turbines should include execution of demonstration projects to further define the operating flexibility and reliability of these units.

To date, none of the CCS projects identified at combined-cycle units have yet progressed to a complete detailed design or full deployment and thus cannot be the basis of a BACT determination for the Project.

Storage

Once captured, CO₂ must be stored underground in suitable geological formations, but not all regions of the U.S. have the required geology. The Plant is performing boring projects to better understand the geologic formations in Georgia and assess the viability of safe and permanent storage of CO₂, but this work is ongoing and exploratory in nature.

Based on Southern Company’s knowledge of geologic investigations across the southeastern U.S., certain areas in southern Alabama remain the closest locations with potentially feasible sites for carbon storage for the Project. However, as explained below, pipeline access to these areas is not available or even under development.

Transportation

Unless captured CO₂ is used or stored at the capture site, it must be compressed and transported to a location with adequate geology for storage. Therefore, transportation of CO₂ via pipeline to a storage location is an essential component of CCS where storage or an available use of the CO₂ is not available at the site. Only a few pipelines are currently used to carry CO₂ in the U.S., primarily

⁴¹ For example, a permit authorizing the installation of CCS was issued to a DOE-funded demonstration project at the Baytown Energy Center in Baytown, Texas. A permit for CCS was also issued to the Quail Run Energy Facility in Odessa Texas, but there is no evidence this project is being funded or moving forward.

⁴² The permit does not identify CCS as BACT for the facility.

linking natural sources of CO₂ sources to oil fields for use in enhanced oil recovery (EOR). However, a national CO₂ pipeline network does not exist, which makes this critical step in the CCS process unavailable in many areas of the country. The only announced proposed CO₂ pipelines under development for CCS have been in the Midwest U.S., spanning the states of Illinois, Iowa, Minnesota, Nebraska, North Dakota, and South Dakota. However, the majority of these projects have been cancelled or delayed.⁴³ There are no existing or planned networks in Georgia. So, while CO₂ transportation via pipeline has been physically demonstrated, CO₂ transportation infrastructure is not commercially available for the Project.

Since carbon capture is not applicable due to the lack of a sufficient commercial scale demonstration, storage is not available at the Project site, and transportation of CO₂ to offsite locations is not available, CCS is not technically feasible for the Project.⁴⁴

Summary and Ranking of Remaining Greenhouse Gases – CO₂ Control Technologies – CC Units (Step 3)

Use of clean/low-emitting fuels, efficient design, and good combustion, operating, and maintenance practices are the only available and technically feasible control options for CO₂ emissions from the proposed CC units and are all inherent to the Project. As such, all of these available technologies are applicable, and no ranking of the three control options is required.

Evaluation of Most Stringent Greenhouse Gases – CO₂ Control Technologies – CC Units (Step 4)

The top control option is proposed for emissions of CO₂ from the proposed CC units. Therefore, no further evaluation of the CO₂ control options is required.

Selection of BACT for Greenhouse Gases – CO₂ CC Units (Step 5)

Based on the Plant review, CO₂ BACT for the proposed CC units should be based on use of clean/low-emitting fuels, efficient design, and good combustion, operating, and maintenance practices. The search results for the combination of these control options, summarized in Appendix E, Tables E-23 and E-24, indicate that the most common form of CO₂ emissions limit for the type of source under consideration is a 12-month rolling average emission rate on a lb CO₂/MWh-gross basis. Based on The Plant's review of the search results and the potentially applicable regulations in Subpart TTTTa:

- The level of control for all CC units of a similar configuration, i.e., 1-on-1, without regard to CT technology, operating mode, or fuel, ranges from 726 to 1,384 lb CO₂/MWh-gross with an average emission limit of approximately 900 lb CO₂/MWh-gross.

⁴³<https://www.rabobank.com/knowledge/d011434507-the-long-haul-to-long-haul-carbon-dioxide-pipeline-development-in-the-us>.

⁴⁴ While CCS is considered technically infeasible, 5 acres for each proposed CC unit have been reserved for capture and compression should this technology become available for utility-scale deployment in the future.

- Emission limits for 1-on-1 CC units that are greater than 1,000 lb CO₂/MWh-gross apply only while burning oil or while operating at low loads.⁴⁵
- Emissions limits for 1-on-1 CC units that are less than 800 lb CO₂/MWh-gross are based on operating at full load without use of duct burners while burning natural gas only.⁴⁶ Otherwise, these units are subject to the Subpart TTTT emission limit of 1,000 lb CO₂/MWh-gross.
- Emission limits for all dual-fuel 1-on-1 CC units range from 850 and 1,384 lb CO₂/MWh-gross when separate limits apply depending on the fuel being burned.⁴⁷ However, when a single limit applies without regard to the fuel burned, the range for dual-fuel 1-on-1 CC units narrows to between 888 and 1,000 lb CO₂/MWh-gross, where the upper bound is the emission limit in Subpart TTTT.⁴⁸
- The potentially applicable regulations in Subpart TTTTa establish a “sliding-scale” emission standard which, for large CTs, ranges from 800 to 1,067 lb CO₂/MWh-gross depending on how much distillate oil was used in the previous 12 operating months.

Based on the above, the Plant proposes the following as CO₂ BACT:

- 905 lb CO₂/MWh-gross based on a 12-operating month rolling average, determined in accordance with the monitoring, recordkeeping, and reporting requirements established in the applicable NSPS.

This emission limit is specific to the type of CT technology and CC configuration of the proposed CC units and accounts for supplemental firing, periods of operation at low loads, and use of distillate oil as a backup fuel.⁴⁹ The emission limit also accounts for unit degradation since BACT must be achievable over the life of the units, and the way the units are operated and the emission performance they can achieve may change over time. This limit is expressed on a carbon dioxide equivalent basis and is intended to cover emissions of CH₄ and N₂O 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.

⁴⁵ CPV Three Rivers (IL-0129) and Nemadji Trail Energy (WI-0300) have emission limits of 1,384 and 1,180 lb CO₂/MWh-gross, respectively, when burning oil. JEC Units 1 and 2 (IL-0130) have an emission limit of 1,190 lb CO₂/MWh-gross when operating at low loads.

⁴⁶ See, for example, Maple Creek Energy (IN-0365) and Long Ridge Energy (OH-0375). The practice of setting this type of emission limit for purposes of BACT appears to be common in Ohio. See also NTE Ohio (OH-0363), Clean Energy Future Lordstown (OH-0366), and Guernsey Power Station (OH-0374).

⁴⁷ Dual-fuel 1-on-1 CC units include CPV Three Rivers Energy Center (IL-0129), Middlesex Energy Center (NJ-0085), and Nemadji Trail Energy Center (WI-0300). Please refer to footnote.

⁴⁸ While CPV, Nemadji, and Middlesex are dual-fuel units, only Middlesex has single limit that includes emissions from burning both natural gas and distillate oil. The Middlesex limit of 888 lb CO₂/MWh-gross includes 720 hours per year of operation on oil.

⁴⁹ The proposed CO₂e BACT limit of 905 lb CO₂e/MWh-gross reflects the estimated performance, i.e., heat rate, of the proposed CC units while firing natural gas at minimum load, or at full pressure with duct burner in-service, at winter conditions and accounts for up to 1,200 hours per year of operation on distillate oil at full load.

The emission factor for CO₂ will be based on 40 CFR Part 75, Appendix G, Eq. G-4, while emissions of CH₄ and N₂O will be based on the current emission factors in 40 CFR Part 98, Table C-2⁵⁰ and the current global warming potentials in 40 CFR Part 98, Table A-1 (1, 28, and 265 for CO₂, CH₄, and N₂O, respectively)⁵¹.

EPD Review – CC Units Greenhouse Gases – CO₂ Control

The RBLC database was reviewed, with the intent of finding similar 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. The Plant's proposed BACT limit is a middle limit of the proposed limits for the facility with 43% that had higher proposed limits.

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

Conclusion – CC Units Greenhouse Gases – CO₂ Control

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

Table 4-7: BACT Summary for the CC Units 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	905 lb CO ₂ /MWh-gross l	12-month rolling average*	CEMS

*** Determined in accordance with the monitoring, recordkeeping, and reporting requirements established in the applicable NSPS.**

⁵⁰ Emission factors are from 40 CFR Part 98 in 78 Federal Register at 71952, November 29, 2013.

⁵¹ Global Warming Potentials for GHGs are from amendments to 40 CFR Part 98 in 89 Federal Register at 31802, April 25, 2024.

CC Units (Source Codes: CT7/DB7-CT10/DB10) – Greenhouse Gases – CH₄ Emissions

Applicant's Proposal

For the proposed CT units, the contribution of CH₄ to total CO₂e emissions is negligible and therefore should not warrant a detailed BACT review. Nonetheless, the following top-down analysis was provided for CH₄ emissions from the proposed CC units.

Greenhouse Gases – CH₄ Emissions Formation – CC Units

Emissions of CH₄ may occur because of incomplete combustion of methane and hydrocarbons in fuel.

Identification of Greenhouse Gases – CH₄ Control Technologies – CC Units Turbines (Step 1)

As discussed above, CH₄ emissions may occur because of incomplete combustion. Good combustion practices are an available control option to reduce CH₄ emissions from the proposed CC units.

Catalyst providers do not offer products to control CH₄ 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 CH₄ particularly difficult. Therefore, good combustion practices are the only available control option for CH₄ emissions from the proposed CC units.

Elimination of Technically Infeasible Greenhouse Gases – CH₄ Control Technologies – CC Units (Step 2)

Good combustion practices are the only available control option for CH₄ emissions from the proposed CC units and are technically feasible.

Summary and Ranking of Remaining Greenhouse Gases – CH₄ Control Technologies – CC Units (Step 3)

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for CH₄ emissions from the proposed CC units.

Evaluation of Most Stringent Greenhouse Gases – CH₄ Control Technologies – CC Units (Step 4)

The top control option – good combustion practices – is proposed for emissions of CH₄ from the proposed CC units. Therefore, no further evaluation of the CH₄ control options is required.

Selection of BACT for Greenhouse Gases – CH₄ CC Units (Step 5)

Good combustion practices are selected as BACT for CH₄ emissions from the proposed CC units. GPC is proposing that a separate numerical limit for CH₄ emissions is unnecessary because CH₄ emissions are included in the proposed GHG limit expressed in CO₂e determined to be BACT for CO₂ above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 28 (per 40 CFR 98 Subpart A, rule effective January 1, 2025).

EPD Review – CC Units Greenhouse Gases – CH₄ Control

For the proposed CC units, the contribution of CH₄ to total CO₂e emissions is negligible and therefore should not warrant a detailed BACT review.

Conclusion – CC Units Greenhouse Gases – CH₄ Control

Refer to the previous review for GHGs.

Combined Cycle (Source Codes: CT7/DB7 - CT10/DB10) – Greenhouse Gases – N₂O Emissions

Applicant's Proposal

For the proposed CC units, the contribution of N₂O to total CO₂e emissions is also negligible and therefore should not warrant a detailed BACT review. Nonetheless, the following top-down analysis was provided for N₂O emissions from the proposed CC units.

Greenhouse Gases – N₂O Emissions Formation – CC Units

There are five (5) primary pathways of NO_x production in combustion turbines: thermal NO_x, prompt NO_x, NO_x from N₂O intermediate reactions, fuel NO_x, and NO_x formed through reburning. For turbines using DLN combustors, the N₂O pathway is the prevailing mechanism of NO_x formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with N₂O, creating N₂ and NO.⁵² In premixed gas flames, N₂O is primarily formed in the flame front or oxidation zone. Once formed, the N₂O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N₂O 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 N₂O formation zone can increase N₂O 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.⁵³ Therefore, reductions in NO_x can result in incremental increases in N₂O emissions.

Identification of Greenhouse Gases – N₂O Control Technologies – CC Units (Step 1)

Good combustion practices are an available control option to reduce N₂O emissions from the proposed CC units. As discussed above, N₂O formation is limited during complete combustion, since most oxides of nitrogen will tend to oxidize completely to NO₂, which is not a GHG.

Additionally, N₂O catalysts are a potential control option, as they have been used in nitric/adipic acid plant applications to minimize N₂O emissions.⁵⁴ Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with an N₂O catalyst followed by ammonia injection and a NO_x catalyst.

⁵² Angello, L., Electric Power Research Institute, Fuel Composition Impacts on Combustion Turbine Operability, March 2006.

⁵³ American Petroleum Institute, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, February 2004

⁵⁴ N₂O 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 – N₂O Control Technologies – CC Units (Step 2)

N₂O catalyst providers do not offer products to control N₂O emissions from combustion turbines due to the very low N₂O concentrations present in exhaust streams (approximately 5 ppm).⁵⁵

Since N₂O catalysts are not available, good combustion practices are the only available control option and are technically feasible.

Summary and Ranking of Remaining Greenhouse Gases – N₂O Control Technologies – CC Units (Step 3)

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for N₂O emissions from the proposed CC units.

Evaluation of Most Stringent Greenhouse Gases – N₂O Control Technologies – CC Units (Step 4)

The top control option – good combustion practices – is being proposed for emissions of N₂O from the proposed CC units. Therefore, no further evaluation of the N₂O control options is required.

Selection of BACT for Greenhouse Gases – N₂O CC Units (Step 5)

Good combustion practices are selected as BACT for N₂O emissions from the proposed CC units. The Plant is proposing that a separate numerical limit for N₂O emissions is unnecessary because N₂O emissions are included in the proposed GHG limit expressed in CO₂e determined to be BACT for CO₂ above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 265 (per 40 CFR 98 Subpart A, rule effective January 1, 2025).

EPD Review – CC Units Greenhouse Gases – N₂O Control

For the proposed CC units, the contribution of N₂O to total CO₂e emissions is also negligible and therefore should not warrant a detailed BACT review.

Conclusion – CC Units Greenhouse Gases – N₂O Control

Refer to the previous review for GHGs.

⁵⁵ 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

Cooling Towers BACT Review

Particulate Matter

Formation

In wet cooling towers, some liquid water droplets may be entrained in the cooling air stream and carried out of the tower. These droplets are referred to as "drift" and may contain dissolved solids. PM emissions occur when the droplets evaporate, leaving behind solid particles.

Step 1 – Identify Control Options for Evaluation

The Plant searched the RBLC for BACT determinations for PM emissions from cooling towers associated with power generation. The results of this search are summarized in Appendix E of the application, Table 25.

Based on these results, the only potentially available control option to reduce PM emissions from the cooling towers is high-efficiency drift eliminators. Drift eliminators consist of baffles located at the top of a cooling tower that are designed to prevent water droplets from escaping the tower by causing the droplets to change direction and lose velocity, and by impaction on the baffle blades resulting in agglomeration of droplets.

Step 2 – Eliminate Technically Infeasible Control Options

High-efficiency drift eliminators are inherent to the Project and technically feasible.

Step 3 – Rank Remaining Control Options

No ranking of control options is required, as high-efficiency drift eliminators are the only available and technically feasible control option for PM emissions from the cooling towers.

Step 4 – Evaluate Remaining Control Options

The top control option is proposed for emissions of PM from the cooling towers. Therefore, no further evaluation of the PM control options is required.

Step 5 – Select BACT

Based on the Plant review, PM BACT for the cooling towers should be based on the use of high-efficiency drift eliminators.

Based on the search results, drift rates for high-efficiency drift eliminators range from 0.0005 to 0.001% of circulating water flow. Based on this information, The Plant is proposing to install drift eliminators with a drift rate of 0.0005% as PM BACT for the cooling towers.

EPD Review – Cooling Towers PM Control

GA EPD agrees that high-efficiency drift eliminators with a drift rate of 0.0005% as PM BACT for the cooling towers

Conclusion – Cooling Towers – PM Control

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

Table 4-8: BACT Summary for the Cooling Towers – PM Control

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	High-efficiency Drift Eliminators	0.0005% drift rate	N/A	Monitoring of drift rate and Total Dissolved Solids (TDS)

Water Bath Heaters – BACT Review

Water Bath Heaters – NOx Emissions

Applicant's Proposal

Associated equipment associated with the Project includes:

- Four (4) natural gas-fired water bath heaters, each with a heat input rating of less than 10 MMBtu/hr.

NOx Formation – Heaters

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

Identification of NOx 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 NOx emissions from the proposed water bath heaters. Generally, NOx 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 NOx 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 NOx 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-26, 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 NOx burners), as BACT. Add-on controls potentially applicable to the proposed water bath heaters include SCR, selective non-catalytic reduction (SNCR), and non-selective catalytic reduction (NSCR).

Elimination of Technically Infeasible NOx 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 NOx 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 water bath 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 water bath 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 water bath 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 – Water Bath 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 water bath heaters.

Evaluation of Most Stringent NO_x Controls – Water Bath Heaters (Step 4)

The top control options are being proposed for NO_x emissions from the proposed water bath 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 water bath heaters since they are too small to be regulated under NSPS Subpart Dc.

NO_x BACT for the proposed water bath 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 water bath 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% O₂, 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 O₂) will be conducted using the procedures of ASTM D 6522, CTM-030, or EPA reference methods 7E and 3A.

EPD Review – Heaters NO_x Control

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

- USEPA RACT/BACT/LAER Clearinghouse⁵⁷
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM₁₀, CO, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Heaters NO_x Control

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

The only facilities that state the NO_x emission limit of 0.011 lb/MMBtu as BACT for the heaters of varied sizes 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
- Chickahominy Power, LLC, 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 NO_x 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 4-9:

Table 4-9: 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% O ₂ , or 0.011 lb/mmBtu	N/A	Biennial tune-up

Water Bath Heaters – CO Emissions

Applicant's Proposal

CO Formation – Water Bath Heaters

CO emissions from the proposed water bath 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 – Water Bath 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 water bath 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 water bath 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 CO₂. Based on the RBLC search results provided in Appendix E of the application, Table E-28, 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 water bath heaters include oxidation catalysts.

Elimination of Technically Infeasible CO Control Options – Water Bath 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 CO₂ 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 water bath 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.

Summary and Ranking of Remaining CO Controls – Water Bath 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 CO emissions from the proposed water bath heaters.

Evaluation of Most Stringent CO Controls – Water Bath Heaters (Step 4)

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

Selection of Emission Limits for CO BACT (Step 5)

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

CO BACT for the proposed water bath 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 water bath 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 water bath heaters that have emission limits for both of these pollutants (AL-0329). The CO emission limit for these water bath 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% O₂, 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 O₂) will be conducted using the procedures of ASTM D 6522, CTM030, or EPA reference methods 10 and 3A.

EPD Review – Heaters 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 Clearinghouse⁵⁹
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

⁵⁸ *Id.*

⁵⁹ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

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 4-10:

Table 4-10: 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% O ₂ , or 0.074 lb/mmBtu	N/A	Biennial tune-up

Water Bath Heaters – VOC Emissions

Applicant's Proposal

VOC Formation – Heaters

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

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 water bath 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-29, 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 water bath heaters include oxidation catalysts.

Elimination of Technically Infeasible VOC Control Options – Water Bath 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 CO₂ 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 water bath 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 – Water Bath 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 water bath heaters.

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

The top control options are being proposed for VOC emissions from the proposed water bath 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 water bath heaters since they are too small to be regulated under NSPS Subpart Dc.

VOC BACT for the proposed water bath 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 water bath 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 water bath heaters limited to 9 ppmvd NO_x and 100 ppmvd CO. Water bath 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 water bath heaters should not exceed 20 ppmvd (as methane), corrected to 3% O₂, or 0.010 lb/MMBtu. However, instead of a numerical BACT limit, The Plant 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 Clearinghouse⁶⁰
- 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.

⁶⁰ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

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
VOC	Natural Gas and good combustion practices	20 ppmvd, corrected to 3% O ₂ or 0.010 lb/MMBtu	N/A	Fuel Records

Water Bath Heaters – PM Emissions

Applicant's Proposal

PM Formation – Water Bath Heaters

PM emissions from fuel-burning equipment such as the proposed water bath 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 – Water Bath 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 water bath heaters. Based on the RBLC search results provided in Appendix E of the application, Table E-30 (PM), 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 water bath 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 – Water Bath 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 – Water Bath 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 water bath heaters.

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

The top control options are being proposed for PM emissions from the proposed water baths. 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 water bath heaters since they are too small to be regulated under NSPS Subpart Dc.

PM BACT for the proposed water bath 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 water bath 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 water bath heaters should not exceed 0.005 lb/MMBtu. However, instead of a numerical BACT limit, GPC is proposing exclusive use of natural gas as BACT.

EPD Review – Water Bath 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 Clearinghouse⁶²
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Water Bath Heaters PM Control

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

47% of the heater entries in the RBLC database for small water bath heaters state PM emission limits in the range of 0.007 to 0.0075 lb/MMBtu as BACT including, for example;

- 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 PM₁₀

The Division agrees with PM emission limit of 0.005 lb/MMBtu proposed by the Plant. 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 Water Bath Heaters is summarized below in Table 4-12:

Table 4-12: BACT Summary for the Water Bath Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Natural Gas and good combustion practices	0.005 lb/MMBtu	N/A	Fuel Records

Water Bath Heaters – SO₂ Emissions

Applicant's Proposal

SO₂ Formation – Water Bath Heaters

Emissions of SO₂ occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO₂ emissions associated with combustion of natural gas are very low due to the low concentration of sulfur compounds in the fuel.

Identification of SO₂ Control Technologies – Water Bath Heaters (Step 1)

For SO₂, The Plant also searched RBLC to identify potential control options for the proposed water bath heaters. The result of this search is summarized in Appendix E, Table E-27 of the application. Based on this review, no add-on control options were identified. Instead, many facilities listed some variation of use of clean fuels with inherently low sulfur content and good combustion practices as BACT.

The only potentially available control option for SO₂ emissions from the proposed water bath heaters is use of clean fuels with inherently low sulfur content. Conventional add-on controls are not commercially available for such sources because the use of clean fuels inherently results in a low level of emissions.

Elimination of Technically Infeasible SO₂ Control Options – Water Bath Heaters (Step 2)

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

Summary and Ranking of Remaining SO₂ Controls – Water Bath Heaters (Step 3)

No ranking of control options is required, as use of fuels with inherently low sulfur content is the only available and technically feasible control option for SO₂ emissions from the proposed water bath heaters.

Evaluation of Most Stringent SO₂ Controls – Water Bath Heaters (Step 4)

The top control option is being proposed for SO₂ emissions from the proposed water bath heaters. Therefore, no further evaluation of the impacts of the control options is required.

Selection of Emission Limits for SO₂ BACT (Step 5)

Based on our review, SO₂ BACT for the proposed water bath heaters should be based on use of fuels with inherently low sulfur content. The plant proposes to exclusively fire pipeline quality natural gas in these water bath heaters.

EPD Review – Water Bath Heaters SO₂ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO₂ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse⁶³
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

Conclusion – Water Bath Heaters SO₂ Control

The technically feasible control technologies for SO₂ emission control for the water bath heaters are use of natural gas with inherently low sulfur content.

25% of the heater entries in the RBLC database for small water bath heaters state SO₂ emission limits in the range of 0.0006 to 0.0011 lb/MMBtu as BACT including, for example;

- Calcasieu Pass LNG Project, 0.0006 lb/MMBtu
- Greenville Power Station, 0.0011 lb/MMBtu
- Wildcat Point Generation Facility, 0.0006 lb/MMBtu

The Division agrees with the proposed BACT control technology of use of natural gas with inherently low sulfur content and good combustion practices.

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

Table 4-13: BACT Summary for the Water Bath Heaters

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO ₂	Natural Gas and good combustion practices	Exclusive use of natural gas	N/A	Fuel Records

⁶³ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

Water Bath Heaters – GHG Emissions

Applicant's Proposal

GHG Formation – Water Bath Heaters

As with the proposed CC units, GHG emissions that result from the combustion of natural gas in the proposed water bath heaters include CO₂, CH₄, and N₂O.

Identification of GHG Control Technologies – Water Bath Heaters (Step 1)

Based on the RBLC search results provided in Appendix E of the application, Table E-31, no add-on control options were identified that would reduce GHG emissions from the proposed water bath 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 water bath heaters.

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

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

Summary and Ranking of Remaining GHG Controls – Water Bath 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 water bath heaters.

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

The top control options are being proposed for emissions of GHG from the proposed water bath 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 water bath heaters.

GHG BACT for the proposed water bath heaters is based on the exclusive use of natural gas as fuel and good combustion practices. The Plant 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 Clearinghouse⁶⁴
- 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.

Since no emission limits for GHG were identified for the water bath 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 Water Bath Heaters is summarized below in Table 4-13:

Table 4-14: BACT Summary for the Water Bath Heaters

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

⁶⁴ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

Diesel Storage Tanks – BACT Review

Diesel Storage Tank – 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 and 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 tanks. Based on the RBLC search results provided in Appendix E of the application, Table E-32, 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. Partially or fully insulating the tank roof and/or shell is another method that may be used to decrease breathing losses by reducing the average daily vapor pressure and temperature ranges of the liquid stored.

On October 15, 2024, EPA finalized NSPS Subpart Kc, which applies to certain volatile organic liquid storage vessels, including petroleum liquid storage vessels.⁶⁵ Similar to the previous version of the standard, Subpart Kb, EPA requires 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). However, this standard does not apply to the proposed diesel storage tanks 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.

⁶⁵ 89 Fed. Reg. 83296 (October 14, 2024).

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

Use of submerged filling and light or reflective tank surface colors is technically feasible, as is partially or fully insulating the tank. While use of light or reflective tank surface colors is technically feasible, the Plant did not consider this control option further since the Plant anticipates that the tank roof and shell will be fully insulated.⁶⁶

The Plant could not identify a case where the remaining control options noted in Step 2 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.⁶⁷ Therefore, use of submerged filling and light or reflective tank surface colors and partially or fully insulating the tank roof are the only technically feasible control options.

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

No ranking of control options was required, as use of submerged filling and insulating the tank are the only available and technically feasible control options for VOC emissions analyzed for from the proposed diesel storage tank.

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

The top control options – use of submerged filling and insulation of the tank – are being proposed for emissions of VOC from the proposed diesel storage tank. Therefore, no evaluation of the remaining VOC control options in Step 2 is required.⁶⁸

⁶⁶ When the tank roof and shell are fully insulated, the average daily vapor pressure and temperature ranges are taken to be zero which makes vapor space expansion factor, the key cause of breathing losses, solely a function of tank vent pressure and vacuum settings for unheated tanks. See U.S. EPA, AP 42, 5th Edition, Volume I, Chapter 7: Liquid Storage Tanks at 16 (October 2024). Available at https://www.epa.gov/system/files/documents/2024-10/c7s1_2024_clean.pdf.

⁶⁷ 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

⁶⁸ 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.

Selection of Emission Limits for VOC BACT (Step 5)

The Plant selected VOC BACT for the proposed diesel storage tanks as use of submerged filling and fully insulating the tank. 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. Fully insulating the tank roof and shell will minimize vapor expansion above the liquid surface. Evaporative losses have a strong correlation with temperature of liquid product stored and reducing liquid product temperature can minimize evaporative losses.

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

In comparing the facility to other similar units, the Division has determined BACT for the fuel oil storage tank to be good maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and to minimize evaporative losses, either fully insulating the tank or selection of tank roof and shell paint colors which have low solar absorptance.

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

Table 4-15: BACT Summary for the Tank

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Maintenance Practices Submerged fill pipe Insulation of Tank or Low Solar Absorption Paint Colors	Tank Design	N/A	Tank Design

Emergency Generator and Fire Water Pump Engine BACT Review

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

Associated equipment associated with the Project includes:

- Four (4) ULSD-fired emergency generators with a standby rating of approximately 1,500 kW and
- Two (2) ULSD-fired fire water pump engines with a continuous rating of approximately 260 kW (350 bhp).
- Two (2) 500 kW emergency generators associated with support buildings

Each emergency generator will be compression ignition, certified to Tier 2 emission standards, and be operated no more than 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. The fire water pump engines will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 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. All emergency generators and fire water pump engines will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

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, manufacturers 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 generators must be certified to Tier 2 standards,

while the fire water pump engines must be certified to Tier 3 standards.⁶⁹ 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 generators and fire water pump engines 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.

⁶⁹ 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 Generators and Fire Water Pump Engines – NOx Emissions

Applicant's Proposal

NOx Formation – Engines

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

Identification of NOx Control Technologies – Engines (Step 1)

As discussed above, available control options for NOx emissions from the proposed emergency generators and fire water pump engines 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-33, 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 NOx 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.⁷⁰ Therefore, Tier 4 is also considered technically feasible.

Summary and Ranking of Remaining NOx 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 NOx Controls – Engines (Step 4)

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for NOx to be between ~\$240,000 and \$400,000 per ton when applied to emergency engines with similar power ratings.⁷¹ Therefore, Tier 4 is eliminated from this BACT analysis for

⁷⁰ 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>.

⁷¹ 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 NOx 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 NOx at this level of cost-effectiveness when used as emergency engines are not commercially available.

both the proposed emergency generators and fire water pump engines 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 generators and fire water pump engines is based on compliance with NSPS Subpart IIII. The Plant 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 NO_x Control

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

- USEPA RACT/BACT/LAER Clearinghouse⁷²
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM₁₀, CO, Greenhouse Gases, H₂SO₄ and VOC BACT analyses.

Conclusion – Engines NO_x Control

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

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 approximately 37% of the emergency generator entries and approximately 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 Arkansas, 3,634 hp, 5.6 g/kw-hr
- Midwest Fertilizer Company, 3,600 hp, 4.42 g/hp-hr
- Nucor Steel, 3,000 hp, 4.8 g/hp-hr
- Sycamore Riverside Energy LLC, 2,011 hp, 4.56 g/hp-hr
- Shintech Louisiana, LLC, 552 hp, 4 g/kw-hr
- Lincoln Land Energy Center, 320 hp, 4 g/kw-hr
- MEC North. LLC and MEC South LLC, 300 hp, 3 g/bhp

⁷² <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 up to 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, including up to 100 hrs/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations.

The BACT selection for the Engines is summarized below in Table 4-16:

Table 4-16: BACT Summary for the Engines

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

Emergency Generator and Fire Water Pump Engine – CO Emissions

Applicant's Proposal

CO Formation – Engines

CO emissions from the proposed emergency generators and fire water pump engines 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 generators and fire water pump engines 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-35, there is one case in which Tier 4 was listed as BACT for an emergency engine. However, the CO emission standard for Tier 2, 3, and 4 engines for the same engine category and model year with similar power ratings is identical (3.5 g/kW-hr), so there are no additional CO emissions reductions to be obtained from use of a Tier 4 engine.⁷³

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.

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)

No ranking of control options is required, since there are no control options that reduce CO emissions more than purchase of a Tier 2 emergency engine and a Tier 3 fire water pump engine.

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.

⁷³ 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.

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 Clearinghouse⁷⁴
- 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 approximately 55% of the emergency generator entries and approximately 42% for the firewater pump entries, some for example are;

- LBLW Erickson Station, 6,000 hp, 3.5 g/kw-hr
- Cronus Chemicals, 3,985 hp, 3.5 g/kwh (2.6 g/hp-hr): 369 hp, 3.5 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- Sycamore Riverside Energy LLC, 2,011 hp, 2.6 g/hp-hr
- Shintech Louisiana, LLC, 552 hp, 4 g/kw-hr
- Belle River Combined Cycle Plant, 399 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 4-16.

⁷⁴ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

Emergency Generator and Fire Water Pump Engine – VOC Emissions

Applicant's Proposal

VOC Formation – Engines

As with CO emissions, VOC emissions from the proposed emergency generators and fire water pump engines 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 generators and fire water pump engines 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-36, 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.⁷⁵ 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

⁷⁵ 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. The Plant 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.

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 Clearinghouse⁷⁶
- 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 RBL database are approximately 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
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- Magnolia Power Generating Station, 2,937 hp, 4.8 g/hp-hr
- Riverview Energy Corporation, 2,800 hp, 6.4 g/kw-hr
- Shintech Louisiana, LLC, 552 hp, 4 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.

⁷⁶ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

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 4-15.

Emergency Generator and Fire Water Pump Engine – PM Emissions

Applicant's Proposal

PM Formation – Engines

PM emissions from the proposed emergency generators and fire water pump engines 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 generators and fire water pump engines 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-37, 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.⁷⁷ The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours.

⁷⁷ 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.

This is true for the proposed emergency generators, which will be operated for a maximum of 200 hours pursuant to Rule (mmm) and for the proposed fire water pump engines, which will be operated for a maximum of 500 hours per year. 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. The Plant 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.

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 Clearinghouse⁷⁸
- 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 approximately 42% of the emergency generator entries and approximately 45% for the firewater pump entries, some for example are;

- Cronus Chemicals, 3,985 hp, 0.2 g/kwh (0.15 g/hp-hr), 369 hp, 0.2 g/kw-hr
- Duke Energy Indiana, Inc.- Cayuga Generating Station, 2,000 hp, 0.2 g/kwh
- Nucor Steel Arkansas, 3,634 hp, 0.2 g/kw-hr
- MEC North. LLC and MEC South LLC, 1,341 hp, 0.2 g/kw-hr
- Shintech Plaquemine Plant 4, 552 hp, 0.2 g/kw-hr
- Belle River Combined Cycle Plant, 399 hp, 0.2 g/kw-hr
- LBLW Erickson Station, 4,474 kw, 0.2 g/kw-hr
- Lincoln Land Energy Center, 1,250 kw, 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.

⁷⁸ <http://cfpub1.epa.gov/rblc/htm/bl02.cfm>

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 4-16.

Emergency Generator and Fire Water Pump Engine – GHG Emissions

Applicant's Proposal

GHG Formation – Engines

As with the proposed CC units, GHG emissions that result from the combustion of ULSD in the proposed emergency generators and fire water pump engines include CO₂, CH₄, and N₂O.

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-38, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generators and fire water pump engines. 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 pumps 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 generators and fire water pump engines are insignificant. CCS should only be considered as an available control option for facilities that emit CO₂ in larger amounts, or for industrial facilities with high-purity CO₂ streams, consistent with past EPA guidance.⁷⁹ GPC's analysis of CCS for the proposed CC 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 CC 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 generators and fire water pump engines.

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.

⁷⁹ 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 generators and fire water pump engines.

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

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

Selection of Emission Limits for GHG BACT (Step 5)

GHG BACT for the proposed emergency generators 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.

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 CO₂ 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 CO₂ 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, including 100 hours/yr for maintenance checks and readiness testing. 50 hours/yr may be used in non-emergency situations

The BACT selection for the Engines is summarized below in Table 4-17:

Table 4-17: 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 engines will be operated for a maximum of 500 hours per year, including 100 hrs/yr for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations	N/A	Comply with NSPS IIII

Applicant's Proposal – Summary of Proposed BACT

Table 4-18 summarizes the proposed BACT limits and compliance demonstration methods for each of the Project's proposed emission units.

Table 4-18. Proposed BACT Emission Limits and Compliance Demonstration Methods

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
Combined Cycle Units	NO_x	Natural gas	DLN Combustors, Water Injection, and Selective Catalytic Reduction (SCR)	2.0 ppmvd NO _x , corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Distillate oil		5.0 ppmvd NO _x , corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Both		203.7 tons NO _x or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-mo rolling total
	CO	Natural gas	Good combustion Practices and Oxidation Catalyst	2.0 ppmvd CO, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	CEMS, 24-hour rolling average
		Distillate oil		2.0 ppmvd CO, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	CEMS, 24-hour rolling average
		Both		257.4 tons CO or less during any 12-month consecutive period, including periods of	CEMS, 12-mo rolling total

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
				startup, shutdown, and fuel switching	
	VOC	Natural gas	Good Combustion Practices and Oxidation Catalyst	1.0 ppmvd VOC, as methane, corrected to 15% O ₂ , duct burner not in service	3-run stack test EPA Reference Method 25A
		Distillate oil		2.0 ppmvd VOC, as methane, corrected to 15% O ₂ , duct burner in service	
	PM	Natural gas	Low Sulfur Content fuels	0.0045 lb/MMBtu	3-run stack test EPA Reference Methods 5 and 202
		Distillate oil		0.0135 lb/MMBtu	
	SO ₂ and H ₂ SO ₄	Natural gas	Low Sulfur Content 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/Low Emitting fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices	905 lb CO ₂ e/MWh-gross	CEMS, 12-mo rolling average

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
Emergency Generators	NO _x , SO ₂ , CO, VOC, PM	Distillate oil	NSPS Subpart IIII	Purchase Tier 2 Engine Ultra-low sulfur diesel	Comply with Rule (mmm) and NSPS Subpart IIII
	GHG	Distillate oil	Clean/ Low Emitting Fuels	Ultra-low sulfur diesel	Comply with Rule (mmm) and NSPS Subpart IIII
Fire Water Engine Pumps	NO _x , SO ₂ , CO, VOC, PM	Distillate oil	NSPS Subpart IIII	Purchase Tier 3 Engine Ultra-low sulfur diesel	Comply NSPS Subpart IIII
	GHG	Distillate oil	Clean/ Low Emitting Fuels	Ultra-low sulfur diesel	Comply with NSPS Subpart IIII
Fuel Oil Storage Tank	VOC	Distillate oil	Good Maintenance Practices Submerged fill pipe Insulation of Tank or Low Solar Absorption Paint Colors	Tank design	Tank design
Water Bath Heaters	NO _x	Natural gas	Ultra-low NO _x Burners and Good Combustion Practices	9 ppmvd, corrected to 3% O ₂ , or 0.011 lb/MMBtu	Biennial tune-up
	CO	Natural gas	Good Combustion Practices	100 ppmvd, corrected to 3% O ₂ , or 0.074 lb/MMBtu	Biennial tune-up

Emissions Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
	VOC	Natural gas	Good Combustion Practices	20 ppmvd, corrected to 3% oxygen, as methane, or 0.010 lb/MMBtu.	Fuels records
	PM	Natural gas	Low Sulfur Content Fuel	0.005 lb/MMBtu	Fuels records
	SO ₂	Natural gas	Low Sulfur Content Fuel	Exclusive use of natural gas	Fuels records
	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 CC 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 NO_x emission limits via a CEMS are not subject to the requirement to perform initial and annual NO_x stack tests.⁸⁰ Initial compliance with the applicable NO_x emission limits will be demonstrated by comparing the arithmetic average of the NO_x emissions measurements taken during the initial RATA to the NO_x emission limit under this subpart.⁸¹

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 NO_x 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 NO_x 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 NO_x CEMS meeting the requirements of 40 CFR Part 75 Appendix E should be sufficient for NSPS Subpart KKKK NO_x compliance monitoring purposes.

The proposed primary BACT limits of 2.0 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 NO_x 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 203.7 tpy on a rolling 12-month basis to ensure the minimization of emissions during startup/shutdown periods.

⁸⁰ 40 CFR 60.4340(b), 40 CFR 60.4405

⁸¹ 40 CFR 60.4405(c) and (d)

The Plant will determine and record the mass emission rate (lb/hr) of NO_x 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 NO_x 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 combined-cycle systems (Combustion Turbines CT7, 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 limit of 2.0 ppmvd for both natural gas and fuel oil firing, 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 257.4 tpy to ensure the minimization of emissions during startup/shutdown periods.

Requirements for SO₂

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 SO₂/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 SO₂/MMBtu.

The Acid Rain regulations require that SO₂ 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 SO₂ mass emissions. SO₂ mass emissions from firing pipeline quality natural gas will be estimated using the regulatory default SO₂ emission rate of 0.060 lb SO₂/MMBtu and the applicable quantity of natural gas burned in the combustion turbine. The heat content for the natural gas is 1020 Btu/scf. SO₂ mass emissions from Combustion Turbines CT7, 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 combined-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 PM₁₀ 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 CO₂e emissions will be calculated based on the monthly fuel use, the CO₂ emission factor from Appendix G to 40 CFR 75, the CH₄ and N₂O emission factors from Subpart C to 40 CFR 98, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO₂, 28 for CH₄, and 265 for N₂O). 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: CT7 - 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: CT7 - CT10) will use a water injection system to control NO_x 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: CT7 - 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 NO₂, CO, PM_{2.5}, PM₁₀, SO₂, Ozone (O₃), and lead. PSD increments exist for SO₂, NO₂, and PM₁₀.

The proposed project at the Plant triggers PSD review for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (PM₁₀), particulate matter with an aerodynamic diameter of 2.5 microns and smaller (PM_{2.5}), nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_{2e}), and sulfuric acid mist (H₂SO₄) emissions. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO₂, CO, PM_{2.5}, PM₁₀, Ozone (O₃), 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 (PM₁₀), particulate matter with an aerodynamic diameter of 2.5 microns and smaller (PM_{2.5}), nitrogen oxides (NO_x), 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 an established PSD modeling significance level (MSL) (an ambient concentration expressed in either µg/m³ 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 (PM₁₀), particulate matter with an aerodynamic diameter of 2.5 microns and smaller (PM_{2.5}), nitrogen oxides (NO_x), volatile organic compounds (VOC), and carbon monoxide (CO) 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. 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)	Primary / Secondary (ppm)
PM ₁₀	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
PM _{2.5}	Annual	9 / 15	--
	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 than the available PSD Increment).

U.S. EPA has established PSD Increments for NO_x, SO₂, and PM₁₀; no increments have been established for CO or PM_{2.5} (however, PM_{2.5} increments are expected to be added soon). 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 increases or decreases 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 SO₂ and PM₁₀ 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 PM₁₀ and SO₂ as January 30, 1980, and for NO₂ 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 shows that the proposed project will not cause ambient impacts of CO, SO₂, or PM₁₀ above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

However, ambient impacts above the SILs were predicted for NO_x for the 1-hour and annual averaging periods and PM_{2.5} for the 24-hour and annual averaging periods respectively, requiring NAAQS and Increment analyses be performed for NO_x 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	Annual	693,789.73	3,777,726.87	2.34651²	1	Yes
	1-hour	694,800.00	3,781,100.00	45.22564²	7.5	Yes
PM ₁₀	24-hour	694,800.00	3,781,100.00	4.46682	5	No
	Annual	693,697.55	3,777,726.87	0.3227	1	No
PM _{2.5}	24-hour	694,800.00	3,781,100.00	3.82041	1.2	Yes
	Annual	693,697.55	3,777,726.87	0.30058	0.13	Yes
SO ₂	1-hour	707,460.12	3,784,280.43	6.30478	7.8	No
	3-hour	694,800.00	3,781,100.00	4.10039	25	No
	24-hour	694,800.00	3,781,100.00	0.89228	5	No
	Annual	693,697.55	3,777,726.87	0.07712	1	No
CO	1-hour	694,800.00	3,781,100.00	1460.13638	2000	No
	8-hour	694,800.00	3,781,100.00	233.66829	500	No

1. Secondary PM_{2.5} impacts were estimated with the MERP approach using the project NO_x and SO₂ emissions at the proposed facility.
2. Results differ from the load analysis because NO₂ SIL modeling was run with the ARM2 configuration while the load analysis assuming a flat 90% NO_x to NO₂ conversion rate that is higher than the conversion rate used by ARM2.
3. 50 km is the maximum SIA for 1-hour NO₂ due to AERMOD's validity.
4. Results are lower than shown in the load analysis because only 1 startup event is considered for the 8-hour averaging period. Emissions are proportioned by the start-up event followed by normal operating conditions for the balance of the averaging period.

As indicated in the table above, maximum modeled impacts were below the corresponding SILs for PM₁₀, SO₂, and CO. However, maximum modeled impacts were above the SILs for the Annual and 1-hour NO₂ and the 24-hour and Annual PM_{2.5}. Therefore, a Full Impact Analysis was conducted for the Annual and 1-hour NO₂ and the 24-hour and Annual 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 NO₂ 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 6-5. 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 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)	Background (ug/m ³)	Secondary Impact (ug/m ³)		Total Impact (ug/m ³)	NAAQS (ug/m ³)	Exceed NAAQS?
						Project	Inventory			
NO ₂	1-hour	691,104.14	3,777,188.25	135.217	30.30	N/A	N/A	165.517	188.7	No
	Annual	693,697.55	3,777,726.87	3.51186	4.5	N/A	N/A	8.0119	100	No
PM _{2.5}	24-hour	690,000.00	3,746,000.00	10.11101	16.20	0.13629	4.2944	30.9261	35	No
	Annual	693,697.55	3,777,726.87	2.04266	6.626	0.0027	0.1032	8.77456	9.0	No

1. Broken down into project + inventory contributions. The project contribution was assessed the same way the SIL was. The inventory contribution was intended to represent the background contribution to PM_{2.5} assessed from sources surrounding the facility from a query of 2020 NEI. All actual emissions within a 50-km radius of the facility were considered from point and non-point sources. All point source contributions are included within counties intersected by the 50-km arc and the non-point sources are apportioned by the fraction of a county within the 50-km arc. The resultant 25,953 TPY NO_x and 8,204.4 TPY SO₂ from the inventory are then applied using the MERPs approach with the Tallapoosa, AL virtual source modeled at 3000 TPY for each precursor using the 90-meter stack height.
2. The applicant showed a modeled concentration of 2.14 µg/m³. The DMU determined that this was due to the applicant's inclusion of several offsite inventory sources, including a few large sources that were confirmed to have revoked permits. Details regarding the exclusion of sources are in the narrative.
3. This value is calculated statewide as an annual background for PM_{2.5}, which is taken from the General Coffee site design value. Qualifying atypical events are removed using the integrated plot screening approach. Local source impacts to the monitor were removed using a combination of AERMOD modeling and a secondary contribution analysis.

As indicated in Table 6-5 above, the 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 6-6.

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)	Increment (ug/m ³)	Exceed Increment?
NO ₂	Annual	693,789.73	3,777,728.22	2.6067	25	No
PM _{2.5}	24-hour	692,484.67	3,777,157.73	6.2433	9	No
	Annual	692,901.95	3,777,741.17	1.57806	4	No

Data for worst year provided only

Table 6-6 demonstrates that the impacts are below the corresponding increments for the annual averaging period for NO₂ and the 24-hour and annual averaging periods for PM_{2.5} 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 74 kilometers 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.

Five Class I areas exist within a 300 km range from the Plant facility: 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 five 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 NO₂, PM₁₀ and PM_{2.5}.

The highest modeled concentrations of SO₂, NO₂, PM₁₀, and PM_{2.5} from the Project were compared to each secondary NAAQS as shown in Table 9 of the modeling memo in Attachment C of this document. 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.

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 PM₁₀ 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.

A Level II analysis refines selected Level I input parameters by using representative wind speed and atmospheric stability conditions in the region encompassing both emission source and the sensitive receptor. In contrast, the Level I analysis assumed worst-case parameters (Pasquill-Gifford stability class F and wind speed of 1.0 meters per second) that are not necessarily indicative of local weather patterns that affect visibility when winds blow emission from the plant toward each of these sensitive receptors. See the Level II analysis below and also as presented in Table 8 of the modeling memo in Attachment C of this document.

Table 7-1. Level 2 VISCREEN Results: Cartersville Municipal Airport (KVPC)

Background	Theta	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	118	5.6	50	4.34	0.996	0.08	0.014
	140				2.00	1.055	0.08	-0.024

*VISCREEN was run using a level 2 analysis for an annualized scenario that accounts for 7560 hours per year of natural gas firing and 1200 hours per year of distillate oil firing. Maximum load emissions for each scenario are summed to compute the annual total filterable particulate matter, NO_x, and primary SO₄ from the project. The nearest visibility sensitive class II area within the project's largest SIA was Cartersville Municipal Airport whose fixed base operator, Phoenix Air conducts flight operations 7 days per week from sunrise to sunset (or about 6 am to 8 pm). Therefore, only the worst-case daytime stability classifications were considered for the Level 2 screening analysis (6 AM to 6 PM). Wind directions were categorized into one 22.5-degree sector centered on 91° from which the worst-case daytime stability class was selected. The analysis of KRMG surface data file from 2019-2023 determined the worst-case scenario to be stability class E with the wind speed 4 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)*."

Table 7-2. Facility-Wide TAP Emissions and MER Comparison

Pollutant	CAS No.	Total Potential Emissions (tpy)	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER?
Acetaldehyde	75-07-0	3.72	7.44E+03	1,110	Yes
Acrolein	107-02-8	5.95E-01	1.19E+03	4.87	Yes
Ammonia	7664-41-7	6.82E+02	1.36E+06	24,300	Yes
Benzene	71-43-2	1.43E+00	2.86E+03	31.6	Yes
1,3-Butadiene	106-99-0	1.69E-01	3.38E+02	7.3	Yes
Dichlorobenzene	95-50-1	1.78E-04	3.56E-01	17,400	No
Ethylbenzene	100-41-4	2.98E+00	5.96E+03	243,000	No
Formaldehyde	50-00-0	2.20E+01	4.40E+04	22.1	Yes
Hexane	110-54-3	2.67E-01	5.34E+02	170,000	No
Naphthalene	91-20-3	4.00E-01	8.00E+02	730	Yes
Propylene Oxide	75-56-9	2.70E+00	5.40E+03	657	Yes
Toluene	108-88-3	1.21E+01	2.42E+04	1,220,000	No
Xylenes	1330-20-7	6.03E+00	1.21E+04	24,300	No
Arsenic	7440-38-2	1.08E-01	2.16E+02	0.0567	Yes
Beryllium	7440-41-7	3.55E-03	7.10E+00	0.973	Yes
Cadmium	7440-43-9	1.27E-01	2.54E+02	1.35	Yes
Chromium (total)	7440-47-3	2.03E-01	4.06E+02	58.4	Yes
Cobalt	7440-48-4	7.68E-03	1.54E+01	11.7	Yes
Lead	7439-92-1	1.57E-01	3.14E+02	5.84	Yes
Manganese	7439-96-5	6.68E+00	1.34E+04	12.2	Yes

Mercury	7439-97-6	3.06E-02	6.12E+01	73	No
Nickel	7440-02-0	2.04E-01	4.08E+02	38.6	Yes
Selenium	7782-49-2	2.10E+00	4.20E+03	23.4	Yes
Sulfuric Acid	7664-93-9	2.19E+02	4.38E+05	117	Yes

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 twenty 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 twenty TAPs are below their respective AAC levels.

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

TAP	Averaging Period	AAC (µg/m³)	Max Modeled Conc. (µg/m³)	Above AAC?
Acetaldehyde	15-minute	4500	0.61275	No
	Annual	4.55	0.00272	No
Acrolein	15-minute	23	0.09831	No
	Annual	0.35	0.000447	No
Ammonia	15-minute	2400	53.542	No
	Annual	100	0.41296	No
Arsenic	15-minute	0.2	0.0795	No
	Annual	0.000233	0.000105	No
Benzene	15-minute	1600	1.98	No
	Annual	0.13	0.0021	No
Beryllium	15-minute	0.5	0.0161	No
	Annual	0.004	0.0000201	No
1,3-Butadiene	15-minute	1100	0.0496	No
	Annual	0.03	0.0000802	No
Cadmium	15-minute	30	0.041	No
	Annual	0.00556	0.000126	No
Chromium (III)	24-hour	1.20	0.00866	No
Chromium (VI) Particulate	Annual	0.1	0.0000206	No
Cobalt	24-hour	0.24	0.000139	No
Formaldehyde	15-minute	245	4.43	No
	Annual	0.0909	0.0183	No
Lead	3-month rolling	0.15	0.0151*	No
Manganese	15-minute	500	4.26	No
	Annual	0.05	0.00419	No
Mercury	15-minute	10	0.0215	No
	Annual	0.3	0.000046	No
Naphthalene	15-minute	7500	0.426	No
	Annual	3	0.000435	No
Nickel	24-hour	0.794	0.00564	No
Propylene Oxide	Annual	2.70	0.00163	No
Selenium	24-hour	0.48	0.103	No
Sulfuric Acid	15-minute	300	20.6	No
	24-hour	2.4	1.99	No

NOTE: Location data are not available because the maximum modeled concentrations in the above table are based on a modeling approach which summed the domain-wide maximum concentrations attributed to each source grouping irrespective of time and space.

***The maximum 24-hour modeled concentration was conservatively used to compare with the lead NAAQS**

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-015-0011-V-05-1.

Section 1.0: Facility Description

“The Plant” applied for a permit to construct four (4) combined-cycle (CC) electric generating units, arranged in a 1-on-1 configuration, each of which includes an advanced-class dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator at Plant Bowen (“the Plant”), located in Bartow County, Georgia. Each CT will be capable of firing either pipeline quality natural gas or distillate oil. The proposed project will construct the proposed CT units and will include installation of new associated equipment, such as the four (4) water bath heaters (Emission Unit IDs WBH1, WBH2, WBH3, and WBH4), six (6) emergency generators, two (2) emergency fire water pump engines, four (4) cooling towers, and four (4) distillate oil storage tanks.

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-7 through CT-10, the HRSGs, the Duct Burners, the emergency generators, the emergency fire water pump engines, and four gas heaters to the equipment table or Attachment B, Insignificant Activities Checklist.

New Condition 3.2.5 contains the Heat Input Limit for distillate oil fired in each combustion turbine.

Condition 3.3.3 contains the 40 CFR 63 Subpart DDDDD requirements and was modified to include the new water bath heaters in addition to the startup boilers.

New Condition 3.3.10 contains the work practice standards requirements of 40 CFR 63 Subpart DDDDD as it pertains to the water heaters.

New Conditions 3.3.11 through 3.3.14 contain the 40 CFR 60 Subpart KKKK requirements for the combustion turbines.

New Condition 3.3.15 subjects the combustion turbines to 40 CFR 60 Subpart TTTT or 40 CFR 60 Subpart TTTTa requirements as applicable.

New Conditions 3.3.16 through 3.3.19 contain the 40 CFR 52 (PSD) and 40 CFR 60 Subpart KKKK emission limits and requirements for the combustion turbines.

New Conditions 3.3.20 through 3.3.24 contain the 40 CFR 63 Subpart YYYY requirements for the combustion turbines.

New Condition 3.3.25 contains the PSD emission limits for the water bath heaters.

New Condition 3.3.26 requires the use of a submerged fill pipe for the fuel oil storage tank.

New Conditions 3.4.20 and 3.4.21 contain the Georgia State Rule d for the water heaters.

New Condition 3.4.22 contains the Georgia State Rule d requirements for the combustion turbines.

New Condition 3.4.23 contains the 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 4.2.4 through 4.2.8 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.

New Condition 5.2.27 states the 40 CFR 63 Subpart DDDDD tune-up requirements for the water bath heaters.

New Condition 5.2.28 requires fuel quantity usage monitors on the water bath heaters.

New Condition 5.2.29 contains the monitoring requirements for the combustion turbines.

New Conditions 5.2.30 and 5.2.31 require fuel supplier certifications for the pipeline quality natural gas and fuel oil fired in the combustion turbines.

New Conditions 5.2.32 through 5.2.38 states the quality assessment requirements of the NOx CEMs and the CO CEMs for the combustion turbines.

New Condition 5.2.39 explains the definition of valid operating requirements per NSPS 60 TTTT or NSPS 60 TTTTa.

New Conditions 5.2.40 through 5.2.45 state the 40 CFR 64 (CAM plan) requirements for the combustion turbines.

New Condition 5.2.46 contains additional CMS requirements for the combustion turbines.

New Condition 5.2.47 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 6.1.8 was added to include the additional reporting requirements for the combustion turbines.

New Conditions 6.2.25 through 6.2.27 were modified to provide the recordkeeping and reporting requirements for the new water bath heaters.

New Conditions 6.2.28 through 6.2.30 were added to require recordkeeping of fuel usage requirements in the combustion turbines.

New Conditions 6.2.31 through 6.2.32 were added to require recordkeeping of verification of compliance with NO_x emission limits for the combustion turbines.

New Conditions 6.2.35 through 6.2.37 were added to require recordkeeping of verification of compliance with CO emission limits for the combustion turbines.

New Conditions 6.2.38 through 6.2.40 were added to require recordkeeping of verification of compliance with greenhouse gas emission limits for the combustion turbines.

New Conditions 6.2.41 through 6.2.43 were added to require recordkeeping of verification of compliance with operational limits for the combustion turbines.

New Condition 6.2.44 was added to state the quarterly reporting requirements for the combustion turbines.

New Condition 6.2.45 and 6.2.46 were added to state the Georgia Rule (nnn) recordkeeping and reporting requirements for the combustion turbines.

New Condition 6.2.47 through 6.2.49 were added to state the 40 CFR 60 Subpart TTTT or TTTTa as applicable, recordkeeping and reporting requirements for the combustion turbines.

New Condition 6.2.50 through 6.2.54 were added to state the 40 CFR 63 Subpart YYYY recordkeeping and reporting requirements for the combustion turbines.

New Condition 6.2.55 was added to state the construction and startup notification requirements.

New Conditions 6.2.56 and 6.2.57 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
Bowen Steam-Electric Generating Plant
Cartersville (Bartow County), Georgia

APPENDIX B

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

Contents Include:

1. PSD Permit Application No. TV-905935, dated March 5, 2025
2. Additional Information Package Dated July 1, 2025

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review