

Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

January 2026

Facility Name: Georgia Power Company (GPC) Wansley Combined-Cycle Facility

City: Carrollton

County: Heard

AIRS Number: 04-13-149-00014

Application Number: 29734

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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 Georgia Power Company (GPC) Wansley Combined-Cycle Facility, referred to as the "Plant", for a greenfield permit to construct two (2) combined-cycle (CC) electric generating units and associated equipment, to be located in Heard County, Georgia. The proposed project will include up to two combined-cycle electric generating units, 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. The proposed project will also include the installation of associated equipment for each proposed combustion turbine such as cooling towers, fuel gas heaters, distillate oil storage tanks, emergency generators, and a fire water pump engine. The proposed CC units, along with all associated equipment, will be hereinafter referred to as the "Project". The proposed CC units will be capable of being fueled with either pipeline quality natural gas or ultra-low sulfur distillate oil during winter conditions.

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 nitrogen oxides (NO_x), sulfur dioxide (SO₂), carbon monoxide (CO), volatile organic compound (VOC), particulate matter (PM), particulate matter with an aerodynamic diameter less than 10 microns (PM₁₀), particulate matter with an aerodynamic less than 10 microns (PM_{2.5}), sulfuric acid mist (SAM or H₂SO₄), and greenhouse gases (GHG) emissions were above the PSD significant level threshold.

The Georgia Power Company (GPC) Wansley Combined-Cycle Facility is located in Heard 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 Georgia Power Company (GPC) Wansley Combined-Cycle Facility related to the proposed facility 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 Plant's proposal provides for the application of Best Available Control Technology (BACT) for the control of particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller (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 dioxide (CO), greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO₂e), and sulfuric acid mist (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 200 km of the facility. It has further been determined that the Plant's proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Georgia Power Company (GPC) Wansley Combined-Cycle Facility for the construction and operation of two (2) combined-cycle units and associated equipment. A copy of the draft permit is included in Appendix A. This Preliminary Determination also acts as a narrative for the draft permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On June 9, 2025, Georgia Power Company (GPC) Wansley Combined-Cycle Facility submitted an application for an air quality permit to construct and operate two (2) combined-cycle combustion turbines and associated equipment, such as cooling towers, fuel gas heaters, distillate oil storage tanks, emergency generators, and a fire water pump engine. The facility is located at 1371 Liberty Church Road in Carrollton, Heard County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility’s Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Y	✓		
PM ₁₀	Y	✓		
PM _{2.5}	Y	✓		
SO ₂	Y	✓		
VOC	Y	✓		
NO _x	Y	✓		
CO	Y	✓		
TRS	N/A			✓
H ₂ S	N/A			✓
Individual HAP	Y	✓		
Total HAPs	Y	✓		
Total GHGs	Y	✓		

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

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

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
N/A	N/A	N/A

Based on the proposed Project description and data provided in the permit application, the estimated potential emissions of regulated pollutants from the facility are listed in Table 1-3 below:

Table 1-3: Emissions Increases from the Project

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
TSP ⁽¹⁾	126.9	25	Yes
PM _{2.5} ⁽¹⁾	231.0	10	Yes
PM ₁₀ ⁽¹⁾	232.0	15	Yes
VOC	325.4	40	Yes

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

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
NO _x	414.1	40	Yes
CO	523.9	100	Yes
SO ₂	71.6	40	Yes
CO ₂ e ²	5,515,500.3	75,000	Yes
SAM	109.4	7	Yes
Pb	0.1	0.6	No

The emissions calculations for Tables 1-3 can be found in detail in the facility's PSD application (See Appendix C of Application No. 29734). These calculations have been reviewed and approved by the Division.

Based on the information presented in Tables 1-3 above, the proposed construction and operation of a new combined-cycle facility, as specified per Georgia Air Quality Application No. 29734, is classified as a major source under PSD and triggers PSD permitting requirements because the potential emissions of PM_{2.5}, PM₁₀, CO, NO_x, SO₂, VOC, H₂SO₄, and CO₂e² exceed the PSD significant emissions rate thresholds for those pollutants.

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 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.

2.0 PROCESS DESCRIPTION

According to Application No. TV-29734, the Plant has proposed to construct up to two combined-cycle electric generating units (Emission IDs: CT10/DB10 and CT11/DB11) and associated equipment.

The primary equipment of the Project includes:

- Up to two (2) combined-cycle 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.

Associated equipment associated with the Project includes:

- Two (2) multi-cell wet mechanical induced draft cooling towers with high efficiency drift eliminators
- Two (2) natural gas-fired water bath type fuel gas heaters with ultra-low NO_x burners with a maximum heat input of approximately 8.61 MMBtu/hr (each)
- Two (2) 90' diameter fully insulated distillate oil storage tanks with submerged fill and a working capacity of 2.3 million gallons (each)
- Two (2) Tier 2 1,500 kW emergency generators
- One (1) Tier 2 500 kW emergency generator
- One (1) Tier 3 350 hp fire water pump engine

Combustion Turbines

The CT is the main component of each proposed CC unit (Emission IDs: CT10/DB10 and CT11/DB11) 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. Since natural gas will be the primary fuel fired in the combustion turbines, the total amount of distillate oil fired in each combustion turbine will be limited to 29,600,000 gallons or less during any twelve consecutive months. Exhaust gases, at higher 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

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 steam turbine (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 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

Each proposed CC unit will include a reheating condensing steam turbine (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 the ST receives high-pressure superheated 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 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.

Fuel Gas Heaters

The Project will include a fuel gas 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 fuel gas 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 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 two (2) 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 Engine

The Project will include up to two (2) 1,500 kW emergency generators and one (1) 350 hp fire water pump engine associated with the proposed CC units. The Project will also include one (1) 500 kW emergency generator associated with a support building. 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 engine will also be compression ignition, certified to Tier 3 emissions 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 the fire water pump engine will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

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 opacity of visible emissions from a source not subject to some other visible emissions limitations under GRAQC 391-3-1-.02 to less than 40% opacity. This standard applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys, or similar structures. Only the emergency generators and fire water pump engine in this project are subject to Rule (b). It is expected that the opacity of 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 visible emissions, PM emissions, and NO_x emissions from fuel-burning equipment. The standards are based on construction date, maximum heat input capacity, and type of fuel(s) combusted. As defined in 391-3-1-.01(cc), fuel burning equipment is:

“Fuel-burning equipment” means equipment the primary purposes 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.

Thermal energy from the proposed CC units and fuel gas 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 fuel gas heaters to less than 20% except for one six-minute period per hour of not more than 27% opacity. Allowable PM and NO_x emissions for the proposed CC units and fuel gas heaters vary but are subsumed by more stringent BACT limits.

The emergency generators and fire water pump engine are not subject to Rule (d) because these engines will not produce thermal energy to furnish process heat indirectly and are therefore not considered fuel burning equipment.

Georgia Rule 391-3-1.02(2)(g) – Sulfur Dioxide

Rule (g) limits SO₂ emissions from fuel-burning sources based on heat input capacity. This rule applies to all fuel burning sources, not just fuel-burning equipment subject to Rule (d).

For fuel-burning sources below 100 MMBtu/hr such as the proposed fuel gas heaters, emergency generators, and fire water pump engine, fuel sulfur content is limited to 2.5%, by weight. For those fuel-burning sources above 100 MMBtu/hr such as the combustion turbines and duct burners in the proposed CC units, fuel sulfur content is limited to 3.0%, by weight. In addition to the fuel sulfur content limit, allowable SO₂ emissions from the proposed CC units are 0.8 lb/MMBtu when firing distillate (liquid) oil in the combustion turbines.

The Rule (g) fuel sulfur content limits and SO₂ emission limitation will be subsumed by more stringent BACT limits. Additionally, BACT will subsume the SO₂ emission limitation in the applicable NSPS for the proposed CC units. The emergency generators and fire water pump will be subject to a more stringent fuel sulfur limit in NSPS Subpart IIII (0.0015% by weight) which has been proposed as BACT. The Plant will comply with Rule (g) by using pipeline quality natural gas and distillate oil only.

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) applies to fixed roof storage vessels with capacities exceeding 40,000 gallons which store petroleum liquids with true vapor pressure greater than 1.52 psia. Because distillate oil has a maximum true vapor pressure less than 1.52 psia (0.01 psia), Rule (bb) will not apply to the proposed distillate oil storage tanks.

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 capacities exceeding 40,000 gallons. Because the proposed distillate oil storage tanks will be fixed roof tanks, Rule (nn) will not apply.

Georgia Rule 391-3-1.02(2)(tt) – VOC Emissions from Major Sources

Rule (tt) requires major sources of VOC emissions in counties originally designated nonattainment for the 1-hour ozone and 1997 8-hour ozone NAAQS to apply Reasonably Available Control Technology (RACT) to reduce VOC emissions from sources not covered by a Control Technique Guideline (ie, non-CTG sources). This rule will not apply to the proposed facility as the Plant will be in Heard County, which is not one of the counties covered by this rule.

Georgia Rule 391-3-1.02(2)(uu) – Visibility Protection

This rule requires EPD to provide written notice of a permit application for a proposed major source or a major modification to an existing major stationary source that may have an impact on visibility in a Class I area. The notification must be provided to the federal land manager (FLM) and the federal official charged with direct responsibility for management of any land within any such area. A Class I analysis, along with all FLM correspondence, is provided in Volume II of Application No. TV-29734.

Georgia Rule 391-3-1.02(2)(vv) – Volatile Organic Liquid Handling and Storage

Rule (vv) prohibits sources subject to other state VOC requirements and located in the former 20-county Atlanta ozone nonattainment area from transferring volatile organic liquids into storage tanks greater than 4,000 gallons unless the tank is equipped with submerged fill pipes.

This rule will not apply to the proposed facility as the Plant will be in Heard County, which is not one of the areas covered by this rule. In addition, no other state VOC requirements apply to the proposed distillate oil storage tanks, so Rule (vv) will not be applicable.

Georgia Rule 391-3-1.02(2)(yy) – Emissions of NO_x from Major Sources

Rule (yy) regulates NO_x emissions from major sources in the metro Atlanta area. This rule will not apply to the proposed facility because the Plant will be located in Heard County, which is not one of the areas covered in this rule.

Georgia Rule 391-3-1.02(2)(lll) – NO_x Emissions 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 a 45-county area in and around metro Atlanta. 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

None of the proposed fuel-burning equipment associated with the Project are subject to this rule. The proposed fuel gas heaters will each have a heat input capacity less than 10 MMBtu/hr, while the combined-cycle units have a heat input capacity greater than 250 MMBtu/hr. Additionally, duct burners associated with a combined cycle gas turbine are exempt from this rule under 391-3-1-.02(2)(lll)6.(ii).

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. This rule is not applicable to the proposed CC units because they are too large. Additionally, the fire water pump engine will be exempt from the provisions of this rule because it will not be used to generate electricity

This rule will apply to the emergency generators, which will not be operated more than 200 hours per year to comply with the requirements.

Georgia Rule 391-3-1.02(2)(nnn) – NOx Emissions from Large Stationary Gas Turbines

Rule (nnn) establishes ozone-season NOx limits for large stationary gas turbines located in specified counties in the metro Atlanta area and requires each of the proposed CC units to emit no more than 6 ppm NOx, corrected to 15% oxygen, on a 30-operating day rolling average during the period May 1 through September 30 of each year. Each of the proposed CC units will include an SCR system that will reduce NOx 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 Emissions From Small Fuel-Burning Equipment

Rule (rrr) regulates NOx emissions from small fuel-burning equipment in the metro Atlanta area and requires that small fuel-burning equipment be fired only with natural gas, propane, or LPG, and requires a tune-up of equipment to be performed annually. This rule will not apply to the proposed facility because the Plant will be in Heard County, which is not one of the areas covered in this rule.

Georgia Rule 391-3-1.02(7) — Prevention of Significant Deterioration of Air Quality

Georgia has adopted a regulatory program for PSD permits in 391-3-13.02(7) which the EPA has approved as part of Georgia's SIP. Accordingly, Georgia EPD issues PSD permits for new major sources and major modification pursuant to the requirements of Georgia's regulations. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or all other sources having potential emissions of 250 tons per year or more of any regulated pollutant (a "major stationary source"); or modification of a major stationary source which results in a significant net emission increase of any regulated pollutant (a "major modification"). The PSD regulations require that any major stationary source or major modification meet the following requirements:

- Application of BACT for each regulated pollutant that would increase by a significant amount as a result of the Project
- Analysis of the source's ambient air impact
- Analysis of existing ambient air quality
- Analysis of the impact on soils, vegetation, and visibility
- Analysis of the impact on Class I areas
- Public notification of the proposed plant in a newspaper of general circulation

Volume I of Application No. 29734 includes a discussion of PSD applicability in Section 1 and a BACT analysis in Section 5. All other analyses are provided in Volume II of Application No. 29734.

Georgia Rule 391-3-1.02(10) – Chemical Accident Prevention Provisions

Chemical Accident Prevention Provisions are codified in 40 CFR Part 68 and incorporated by reference into 391-3-13.02(10). Facilities that store regulated substances listed in 40 CFR 68.130 above the substance-specific threshold quantity are subject to these requirements. The proposed CCs will utilize anhydrous ammonia in the SCR units for NO_x control and the Plant expects that the amount of anhydrous ammonia stored will exceed the threshold quantity. Therefore, the Project will be subject to 40 CFR Part 68. The Plant will comply with the requirements of this subpart, Facilities subject to 40 CFR Part 68 are required to submit and maintain a Risk Management Plan (RMP) pursuant to Subpart G. GPC will submit the first RMP no later than the date anhydrous ammonia is present above the threshold quantity as required in 40 CFR 60.150(b)(3).

Georgia Rule 391-3-1.02(11) – Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) is codified in 40 CFR Part 64 and incorporated by reference into 391-3-13.02(11). Under CAM, facilities are required to prepare and submit monitoring plans (i.e., CAM plans) for certain emission 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. However, CAM does not apply to the following types of emissions limits or standards:

- Established after November 15, 1990 pursuant to section 111 or 112 of the Act;
- Establishing stratospheric ozone protection requirements under Title VI of the Act;
- Establishing Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;
- That applies solely under an emissions trading program approved by the Administrator under the Act;
- For which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 64.1

The proposed CC units will be subject to CAM for the NO_x BACT limit. Rule (nnn) and the applicable NSPS each require the proposed CC units to be equipped with NO_x CEMS to monitor compliance. It should also be noted that the proposed CC units will be subject to CAM for the proposed CO and VOC BACT emissions limits. The first CAM plan is not due until the initial Title V permit application and therefore, a CAM plan will be submitted by the Plant during that time.

Georgia Rules 391-3-1.02(12) – Cross State Air Pollution Rule Nox Annual Trading Program; 391-3-1.02(13) – Cross State Air Pollution Rule SO₂ Annual Trading Program; 391-3-1.02(14) – Cross State Air Pollution Rule Ozone Season Annual Trading Program

The Cross-State Air Pollution Rule (CSAPR) requires states to address interstate transport of NO_x and SO₂ emissions that affect downwind states' ability to attain and maintain the ozone and PM_{2.5} NAAQS. CSAPR requirements include compliance with annual NO_x, seasonal NO_x (May 1 through September 30), and annual SO₂ emission allowance programs and are codified at 40 CFR 97 and 391-3-13.02(12) through 391-3-13.02(14). Therefore, the proposed CC units will be subject to this rule.

The Plant will hold sufficient allowances to cover NO_x and SO₂ emissions and will comply with the monitoring, recordkeeping, and reporting requirements set forth by CSAPR, including the installation, certification, operation, and maintenance of CEMS and fuel flow meters for the proposed CC units.

Georgia Rules 391-3-1.03(1) and (2) — Construction (SIP) Permit and Operation (SIP) Permit

SIP permitting requirements apply to facilities performing construction and modification activities that are not exempt under 391-3-13.03(6). The Project will involve construction activities to install the proposed CC units, cooling towers, fuel gas heaters, emergency heaters, and a fire water pump engine. Since potential emissions from the proposed Project will exceed significant emission rates (SER), PSD permitting is required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix A of the Application.

Georgia Rule 391-3-1.03(10) – Title V Operating Permits

The proposed facility will have potential emissions above Title V major source thresholds (100 tpy for any criteria pollutant, 25 tpy for combined HAP, and 10 tpy for any single HAP) for several pollutants. A Title V application will be submitted electronically through the Georgia EPD Online System (GEOS) within 12 months after the source becomes subject to the Title V program.

Georgia Rule 391-3-1.13 -- Acid Rain

The Acid Rain regulations set a cap on SO₂ emissions from power plants by allocating a fixed number of allowances to units subject to the program. The proposed CC units are subject to the Acid Rain regulations for permits, sulfur dioxide, and monitoring in 40 CFR Parts 72, 73, and 75, respectively. An Acid Rain permit application must be submitted 24 months before the units commence commercial operation and include the deadline for monitoring certification. Please note that the Acid Rain permit application is provided in Appendix A of the Application and is submitted in a separate GEOS application.

The Plant will operate in compliance with applicable provisions of the Title IV Acid Rain rules. The Plant will meet the applicable Acid Rain requirements that become effective after the issuance of the Acid Rain permit and will include the new units in its Title IV Acid Rain monitoring plan, as required under 40 CFR Part 72.

Federal Rules

Prevention of Significant Deterioration

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

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

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

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

40 CFR Part 60, Subpart A – General Provisions

All affected sources which are subject to NSPS under 40 CFR Part 60 are subject to the general provisions of 40 CFR Part 60 Subpart A, unless those provisions are specifically excluded by an applicable source-specific NSPS. The general provisions contain notification, performance testing, monitoring, and recordkeeping requirements for the subparts, if applicable.

40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators

NSPS Subpart D applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that were constructed or modified after August 17, 1971. The proposed CC units and fuel gas heaters are not subject to NSPS Subpart D because: (1) the combustion turbines and fuel gas heaters do not meet the definition of "fossil-fuel-fired steam generation unit" and (2) the duct burners are regulated under another NSPS.

40 CFR Part 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

NSPS Subpart Da applies to fossil-fired electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed, modified, or reconstructed after September 18, 1978. The proposed CC units and fuel gas heaters are not subject to NSPS Subpart Da because the proposed combustion turbines and fuel gas heaters are not part of the affected facility subject to this standard and the duct burners are regulated under another NSPS.

40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Db applies to steam generating units with heat input capacities greater than 100 MMBtu/hr that have been constructed, modified, or reconstructed after June 19, 1984. The proposed CC units and fuel gas heaters are not subject to NSPS Subpart Db because: (1) The

combustion turbines and duct burners are regulated under another NSPS and (2) The fuel gas heaters each have a heat input capacity less than 100 MMBtu/hr.

40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Dc applies to steam generating units with maximum heat input capacities between 10 and 100 MMBtu/hr that have been constructed, modified, or reconstructed after June 9, 1989. The proposed CC units and fuel gas heaters are also not subject to NSPS Subpart Dc because: (1) The combustion turbines and duct burners are regulated under another NSPS and (2) The fuel gas heaters have a heat input capacity less than 10 MMBtu/hr.

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, 2023

NSPS Subpart Kc applies to storage vessels with a capacity greater than 200,000 gallons that are used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification commenced after October 4, 2023. The proposed Project will have storage tanks for the distillate oil that will be used for the proposed CC units, emergency generators, and a fire water pump engine.

Pursuant to 40 CFR 60.110c(b)(8), the requirements of NSPS Kc do not apply to storage vessels of any size storing a liquid with a maximum true vapor pressure less than 0.25 psia. Since the maximum true vapor pressure of distillate oil will be much less than 0.25 psia (~ 0.01 psia), the proposed distillate oil storage tanks associated with the Project will not be subject to the requirements of this subpart.

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

NSPS Subpart IIII is applicable to manufactures, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE). A CI engine, or diesel engine, is a type of engine in which the fuel injected into the combustion chamber is ignited by heat resulting from the compression of gases inside the cylinder. The emergency generators and fire water pump engine will be subject to the emission standards in this subpart. The Plant will comply with the emission standards by purchasing engines certified by the manufacturers to the emission standards in 40 CFR 60.4202, as applicable, for the same model year and maximum engine power.

The emergency generators 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 1039. The Plant will comply with all applicable Subpart IIII monitoring, recordkeeping, and reporting requirements. It should be noted that since the engines will be designated and operated as emergency engines, they will be only 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 Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

NSPS Subpart KKKK establishes NO_x and SO₂ emission standards 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, on a higher heating value (HHV) basis. The proposed CC units not be subject to NSPS Subpart KKKK because they are subject to NSPS Subpart KKKKa.

40 CFR Part 60, Subpart KKKKa – Standards of Performance for Stationary Combustion Turbines

NSPS Subpart KKKKa establishes NO_x and SO₂ emission standards for stationary combustion turbines that commence construction, modification, or reconstruction after December 13, 2024, and have a heat input at load equal to or greater than 10 MMBtu/hr, on a higher heating value (HHV) basis. The proposed CC units will be subject to Subpart KKKKa, which imposes NO_x emission standards of 5 ppmvd, corrected to 15% O₂, or 0.018 lb/MWh, when firing natural gas; 42 ppmvd, corrected to 15% O₂, or 0.16 lb/MMBtu, when firing distillate oil, and 96 ppmvd, corrected to 15% O₂, or 0.35 lb/MMBtu/hr, when operating during periods of turbine turning or operating at less than 70 percent of the base load rating and firing either fuel, based on a 4-operating hour rolling average. Turbine turning is limited to 30 hours annually for each combustion turbine.

The proposed CC units will also be subject to an SO₂ emission standard of 0.9 lb/MWh, or a fuel sulfur limit equivalent to 0.060 lb SO₂/MMBtu heat input. The Plant will comply with the NO_x and SO₂ standards in NSPS Subpart KKKKa by equipping the proposed CC units with combustion controls (DLN, water injection, SCR) and by exclusive use of natural gas or distillate oil as fuel.

40 CFR Part 60, Subpart TTTTa – Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Utility Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric 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 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.

The standards in NSPS Subpart TTTTa have been challenged by a coalition of 25 states, including Georgia, in the United States Court of Appeals for the District of Columbia (D.C. Circuit). In addition, President Trump signed an Executive Order on January 20, 2025, entitled "Unleashing American Energy", that requires all agencies to review all regulations that burden domestic energy production, which applies to Subpart TTTTa due to the burdens that would be imposed by the requirement to install and operate carbon capture system on all new baseload combustion turbines. As of the date of this application, litigation in the DC circuit is on hold while EPA reconsiders the

rule. 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 TTTT and TTTTa 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 otherwise considered an area source. The NESHAP allowable emissions limits are most often established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. The NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

Georgia EPD has incorporated these rules by reference under GRAQC 391-3-1.02(9). An analysis of the applicability of each of the potentially applicable subparts is provided below.

40 CFR 63 Subpart A – General Provisions

All affected sources which are subject to a NESHAP under 40 CFR Part 63 are subject to the general provisions of Subpart A unless those provisions are specifically excluded by an applicable source-specific NESHAP. In most cases, a NESHAP promulgated after 1994 includes a table that cross-references the general provisions, showing which general provisions sections are relevant to it.

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

This subpart applies to stationary combustion turbines located at major sources of HAP. Therefore, the proposed CC units will be subject to this rule. The proposed CC units will be subject to a formaldehyde emission limit of 91 ppbv, corrected to 15% O₂, and other associated requirements, including an initial notification and annual 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

This subpart establishes emission limitations and work practice standards for stationary reciprocating internal combustion engines (RICE) located at both major and area sources of HAP emissions. The emergency generators and fire water pump engine will be subject to RICE MACT.

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 60.6590(c)(6), the fire water pump engine will comply with the requirements of this subpart by complying with NSPS Subpart III.

40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This subpart establishes emission limitations and work practice standards for industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. Process heaters are defined 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. The proposed fuel gas heaters are considered "process heaters" for purposes of this subpart. The proposed fuel gas heaters are part of the "designed to burn gas 1 subcategory" and have a heat input rating of less than 10 MMBtu/hr. Therefore, pursuant to 40 CFR 63.7500(e), the proposed fuel gas heaters are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of the Subpart, or the operating limits in Table 4. The proposed fuel gas heaters are subject to the work practice standard outlined in Table 3, which requires a biennial tune-up every two years unless the unit has a continuous oxygen trim system, in which case 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 project.

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 combined-cycle electric generating units associated with the proposed Project would most likely result from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during 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 NO_x, VOC, and CO BACT emissions limits proposed as part of this application. The first CAM plan is not due until the initial Title V permit application and therefore, a CAM plan will be submitted by the Plant during that time.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed Project will result in emissions that are significant enough to trigger PSD review for the following pollutants: filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM₁₀), particulate matter with an aerodynamic diameter of 2.5 microns (PM_{2.5}), NO_x, VOC, CO, sulfuric acid mist (H₂SO₄), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO₂e).

Combined Cycle (Emission ID: CT10/DB10 and CT11/DB11) BACT Review

Combined Cycle (Emission ID: CT10/DB10 and CT11/DB11) – Background

The Plant is in Carrollton in Heard County, Georgia. The proposed facility consists of two (2) combined-cycle electric generating units (Emission ID: CT10/DB10 and CT11/DB11), arranged in a 1-on-1 configuration, each of which includes: an advanced-class dual-fuel combustion turbine (CT) generator, a heat recovery steam generator (HRSG) with natural gas-fired duct burner, and a steam turbine (ST) generator. The key elements of the Project include:

- Two (2) multi-cell wet mechanical induced draft cooling towers with high efficiency drift eliminators
- Two (2) natural gas-fired water bath type fuel gas heaters with ultra-low NO_x burners with a maximum heat input of approximately 8.61 MMBtu/hr (each)
- Two (2) 90' diameter fully insulated distillate oil storage tanks with submerged fill and a working capacity of 2.3 million gallons (each)
- Two (2) Tier 2 1,500 kW emergency generators
- One (1) Tier 2 500 kW emergency generator
- One (1) Tier 3 350 hp fire water pump engine

Combined Cycle (Emission ID: CT10/DB10 and CT11/DB11) – 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 – Combined Cycle Electric Generating Units

NO_x emissions from the proposed CC units generally consists 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). Most NO_x emissions initially form as nitric oxide (NO) when generated by the combustion processes. NO_x emissions are then 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.

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 used lean fuel mixtures. Prompt NO_x levels may also become significant with ultra-low-NO_x burners.

Fuel NO_x occurs when non-elemental nitrogen contained in the fuel is oxidized. Unlike thermal NO_x, fuel NO_x formation is less dependent on combustion variables such as temperature or residence time. Currently, there are no pre-combustion fuel treatment technologies or combustion controls available to reduce fuel NO_x emissions. For this reason, certain NO_x emissions standards contain an allowance for fuel-bound nitrogen (FBN) as part of the emissions limit.⁽³⁾

NO_x emissions from combustion sources fired with distillate oil are typically higher than those fired with natural gas due to higher combustion flame temperatures and FBN. 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 – Combined Cycle Electrical Generating Units (Step 1)

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

- NO_x BACT determinations for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted in the last 10 years (i.e., since 2014) contained in the RBLC;
- Permits and associated applications, if available, for large (>25 MW) CC units not found in 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),⁴
 - Listed as planned and under construction in EIA's Annual Electric Power Industry Report, Form EIA-860 (six additional facilities);⁵

³ For example, see NSPS Subpart GG, 40 CFR 60.332(a)(1) through (4)

⁴ Available at <http://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, Alamos 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

⁵ Available at http://www.eia.gov/electricity/data/eia860m/xls/march_generator2025.xlsx. The following facilities without RBLC entries were identified in EIA-860 as planned and under construction: Magnolia Power, Shady Hills Combined Cycle Facility, Trumbull Energy Facility, Tennessee Valley Authority (TVA) Cumberland Fossil Plant, Intermountain Power Service Corporation – Intermountain Generation Station, and Louisville Gas & Electric Company Mill Creek. Curators of the University of Missouri, MU Combined Heat and Power Plant, was also listed but the relevant documents were not found online.

- New and proposed federal and state emissions standards; and
- Interviews with original equipment manufacturers (OEM) and owners/operators of similar large, advanced class CC units.

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 (NSRC), and selective catalytic reduction (SCR).⁽⁶⁾

Water or Steam Injection

Water or steam injection was determined by EPA to be the best technology for control of NO_x emissions from stationary CT units when the national emissions standards for this source category were first established in 1977.⁽⁷⁾ 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 produce a lean, pre-mixed flame that burns at a lower temperature with less excess oxygen than conventional combustors.⁽⁸⁾

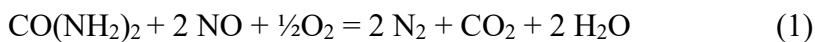
Selective Noncatalytic Reduction

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:

⁶ GPC 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. However, as described elsewhere in this BACT analysis, separate catalytic controls for NO_x and CO/VOC are identified as the top control option and proposed as BACT making evaluation of multipollutant catalysts unnecessary. Additionally, having separate catalytic systems allow GPC flexibility to replace the catalysts at different frequencies to optimize ongoing maintenance costs and emissions performance.

⁷ 42 Fed. Reg. at 53782 and 53785 (Oct. 3, 1977)

⁸ 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.



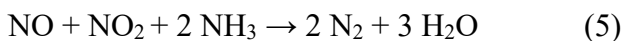
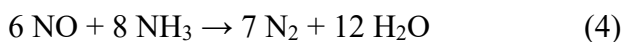
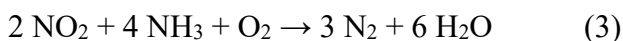
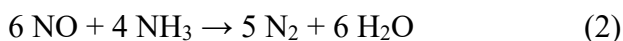
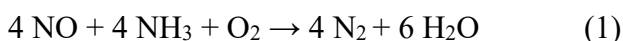
Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls.⁽⁹⁾ An important consideration for SNCR is operating temperature range. The temperature range required for this control option to be effective is approximately 1,600 to 2,000 °F.⁽¹⁰⁾ Operation at temperatures below this range results in ammonia slip. Operation at temperatures above this range results in oxidation of ammonia, forming additional NOX 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 NOx, 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 NOx. However, to ensure NOx 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 control which involves the gas phase reaction of NOx with ammonia or urea injected into the exhaust gas stream in the presence of a catalyst to yield nitrogen and water vapor. The SCR process converts NOx to nitrogen and water vapor by the following chemical reactions:



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

⁹ U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031. Available at <https://www3.epa.gov/ttnecat1/dir1/fsnscr.pdf>.

¹⁰ *Id.*

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 480 and 800 °F. ⁽¹¹⁾

Elimination of Technically Infeasible NO_x Control Options – Combined Cycle Electrical Generating 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. GPC is unaware of any case in which SNCR has been installed and operated successfully on the type of source under review; in the utility industry, this control option is typically applied to electric steam generating units (i.e., boilers). For utility boilers, ammonia is injected into the furnace where temperatures remain high enough for the NO_x reduction reaction to occur (between 1,600 and 2,000°F). The temperature of the exhaust gas from the proposed 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. GPC is unaware of any case in which NSCR has been installed and operated successfully on the type of source under review; this control option is most commonly applied to nonroad and stationary rich-burn spark-ignition internal combustion engines (SI ICE). For rich burn SI ICE, air-to-fuel ratio controllers are used to maintain the low levels of excess oxygen necessary (less than 0.5%) for NSCR to be an effective control option for NO_x emissions. The oxygen content of the exhaust gas from proposed CC units will typically be 10-12%. Therefore, NSCR is not applicable to the proposed CC units. Accordingly, NSCR is not technically feasible.

¹¹ U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-032. Available at <https://www.epa.gov/tncatc1/dir1/fscr.pdf>

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 (Heard) in which GPC 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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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. However, consideration of those impacts could result in a different BACT determination for other sources or projects in areas not subject to Georgia Rule (nnn) or a similar standard that requires uses of SCR.

Selection of Emission Limits for NO_x BACT (Step 5)

Under NSPS Subpart KKKKa, new, large combustion turbines such as the proposed CC units are subject to NO_x emission standards of 5 ppmvd, corrected to 15% O₂, while firing natural gas, 42 ppmvd, corrected to 15% O₂, while firing distillate oil, and 96 ppmvd, corrected to 15% O₂, when operating during periods of turbine turning or at less than 70 percent of the base load rating and firing either fuel, based on a 4-operating hour rolling average.⁽¹²⁾ Turbine turning is limited to 30 hours annually for each combustion turbine. Additionally, as discussed above, the proposed CC units will also be subject to 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 our review, NO_x BACT for the proposed CC units should be based on use of DLN combustors, water injection, and SCR. GPC 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,
- 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.

¹² Except as otherwise noted, all numerical emissions standards and limits referred to in this BACT analysis in terms of parts per million by volume dry (ppmvd) are corrected to 15% O₂.

For natural gas, GPC 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 US., except that those units are gas-fired only and are not capable of firing distillate oil as back-up fuel. ⁽¹³⁾

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. ⁽¹⁴⁾ Sewaren Unit 7 is a second-generation General Electric (GE) H-class unit (GE 7HA.02) and has approximately 30% lower NOx 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, GPC is proposing 5 ppmvd as NOx BACT when firing distillate oil, which is a level of control consistent with NSPS Subpart KKKKa.

Compliance with the NOx BACT emission limits will be determined by CEMS. GPC 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 NOx 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 a combined-cycle operating 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.

¹³ 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)).

¹⁴ Both Middlesex Energy Center and Renovo Energy Center was 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. NOx 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.

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 – Combined-Cycle 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM, CO, SO₂, Greenhouse Gases, H₂SO₄ and VOC BACT analyses.

Conclusion – Combined-Cycle Units NO_x Control

The technically feasible control technologies for NO_x emission control for the combined-cycle units 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 facilities with the most similar combined-cycle units in operation, as well as those listed in the RBLC database, are provided below:

- Alabama Power—Plant Barry (two 744 MW combined-cycle units)
- Jackson Energy Center— (3864.00 MMBtu/hr combined-cycle units)

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

The Division agrees with the proposed limits for normal operation. To account for emissions due to startup, shutdown or malfunction, the Division has decided to include the facility requested limit of 203.7 tons of NO_x emissions (12 consecutive month average) firing natural gas or distillate oil from each of the combined-cycle units (Emission ID: CT10/DB10 and CT11/DB11).

The BACT selection for the Combined-Cycle Units (Emission ID: CT10/DB10 and CT11/DB11) is summarized below in Table 4-1:

Table 4-1: BACT Summary for the Combined-Cycle Units (Emission ID: CT10/DB10 and CT11/DB11)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	Natural Gas	DLN Combustors, Water Injection, and Selective Catalytic Reduction	2.0 ppmvd NOx, corrected to 15% O ₂ , excluding periods of startup, showdown, and fuel switching	4-Hour Rolling Average	NOx CEMS
	Distillate Oil		5.0 ppmvd NOx, corrected to 15% O ₂ , excluding periods of startup, showdown, and fuel switching	4-Hour Rolling Average	NOx CEMS
	Both		203.7 tons NOx or less, including periods of startup, shutdown, and fuel switching	12-Month Rolling Average	NOx CEMS

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – 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 – Combined-Cycle Electrical Generating 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 -- Combined Cycle Electrical Generating Units (Step 1)

GPC 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 available in Appendix D, Tables D-5 through D-8 of the application. 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 KKKKa,⁽¹⁶⁾ and EPA recently confirmed that FGD is "not an applicable alternative for the control of SO₂ emissions" and did 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.

Elimination of Technically Infeasible SO₂ Control Options – Combined Cycle Electrical Generating 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.

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

¹⁶ 89 Fed. Reg at 101306, 101310 (December 13, 2024) (“NSPS Subpart KKKKa proposal”)

Summary and Ranking of Remaining SO₂ Controls – Combined-Cycle Electrical Generating 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 -- Combined-Cycle Electrical Generating Units (Step 4)

The top control options are being proposed for SO₂ 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 SO₂ BACT (Step 5)

Based on GPC's review, SO₂ BACT for the proposed CC units should be based on the use of fuels with inherently low sulfur content. Therefore, GPC 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 – Combined-Cycle Units 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

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

Conclusion – Combined-Cycle Units SO₂ Control

The technically feasible control technology for SO₂ emission control for combined-cycle units is use of fuels with inherently low sulfur content, such as natural gas and distillate oil. Therefore, the Division agrees with the proposal of the exclusive use of natural gas that meets the definition of pipeline quality natural gas as defined in 40 CFR 72.2 and the use of distillate oil with a sulfur content less than 15 ppm, by weight, as SO₂ BACT for the proposed combined-cycle units.

Table 4-2: BACT Summary for the Combined-Cycle Units (Emission ID: CT10/DB10 and CT11/DB11)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
SO ₂	Natural Gas/Distillate Oil	Low Sulfur Content Fuels	Natural gas, 0.5 grains sulfur/100 scf Distillate oil with a sulfur content less than 15 ppm	Fuel Supplier Documentation

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – 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 on CO 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 CO.

CO Formation – Combined-Cycle Electrical Generating 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 operation 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 -- Combined Cycle Electrical Generating Units (Step 1)

GPC reviewed CO 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 available in Appendix D, Tables D-9 through D-12 of the application.⁽¹⁷⁾

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 catalysts.

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 Catalysts

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. 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.

¹⁷ 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 – Combined Cycle Electrical Generating 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 included in the Project because it is necessary to comply with the CT MACT standards (40 CFR 63 Subpart YYYY).

Summary and Ranking of Remaining CO Controls – Combined-Cycle Electrical Generating Units (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 -- Combined-Cycle Electrical Generating 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. However, consideration of those impacts could result in a different BACT determination for other sources or projects not subject to the CT MACT or a similar standard that requires use of oxidation catalyst.

Selection of Emission Limits for CO BACT (Step 5)

Based on GPC's review, CO BACT for the proposed CC units should be based on use of clean fuels, good combustion practices, and an oxidation catalyst. Results indicated 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. 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. GPC 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
- 254.7 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

For both gas and distillate oil, GPC 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 Bary 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 emission 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 CT technology would have been similar were it constructed, the applicant did not propose

supplement 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 limit 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. GPC notes that JEC's permit includes alternate CO limits that apply during low load operations, which are not included in the RBLC information.⁽¹⁸⁾ 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. GPC 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 additional emissions limitations, GPC proposes that compliance with CO BACT be demonstrated on a 24-hour rolling average.

Similar to other CC units permitted by EPD, GPC is proposing short-term emission 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 a combined-cycle operating 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.

¹⁸ 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. GPC notes that the permit does not restrict or limit the amount of time JEC Units 1 and 2 may operate under the alternate limits.

In determining the 24-hour rolling average CO emission 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 – Combined-Cycle Units CO Control

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

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

The same resources have been utilized in preparing the Division's PM, NO_x, SO₂, Greenhouse Gases, H₂SO₄ and VOC BACT analyses.

Conclusion – Combined-Cycle Units CO Control

The technically feasible control technologies for CO emission control for the combined-cycle units are good combustion practices and an oxidation catalyst. Therefore, the combination of an oxidation catalyst and good combustion practices are the demonstrated and technically feasible options to be considered for this Project. The facilities with the most similar combined-cycle units in operation, as well as those listed in the RBLC database, are provided below:

- Alabama Power—Plant Barry (two 744 MW combined-cycle units)
- Jackson Energy Center— (3864.00 MMBtu/hr combined-cycle units)

The limits for the other facilities evaluated above are similar to this facility's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of the use of an oxidation catalyst 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 254.7 tons of NO_x emissions (12 consecutive month average) firing natural gas or distillate oil from each of the combined-cycle units (Emission ID: CT10/DB10 and CT11/DB11).

The BACT selection for the Combined-Cycle Units (Emission ID: CT10/DB10 and CT11/DB11) is summarized below in Table 4-3:

Table 4-3: BACT Summary for the Combined-Cycle Units

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
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	24-Hour Rolling Average	CO CEMS
	Distillate Oil		2.0 ppmvd CO, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	24-Hour Rolling Average	CO CEMS
	Both		254.7 tons CO or less, including periods of startup, shutdown, and fuel switching	12-Month Consecutive Period	CO CEMS

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – 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 on VOC 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 VOC.

VOC Formation – Combined-Cycle Electrical Generating 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 -- Combined Cycle Electrical Generating Units (Step 1)

GPC 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 available in Appendix D, Tables D-13 through D-16 of the application.⁽¹⁹⁾

Potentially available control options for VOC emissions from the proposed CC units are the same as those discussed above for CO: good combustion practices, and post-combustion add-on controls such as an oxidation catalyst.

Good Operating Practices

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

Oxidation Catalyst

An oxidation catalyst uses excess air to convert organic compounds to CO₂ in the presence of catalyst without the use of a reagent. Technical considerations for employing this add-on control option are the same as those discussed above for CO.

Elimination of Technically Infeasible VOC Control Options – Combined Cycle Electrical Generating Units (Step 2)

¹⁹ See footnote 41.

Use of good operating practices is inherent to the Project and technically feasible. The use of an oxidation catalyst is included in the Project because it is necessary to comply with the CT MACT standards (40 CFR 63 Subpart YYYY).

Summary and Ranking of Remaining VOC Controls – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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. However, consideration of those impacts could result in a different BACT determination for other sources or projects not subject to the CT MACT or a similar standard that requires use of oxidation catalyst.

Selection of Emission Limits for VOC BACT (Step 5)

Based on GPC's review, VOC BACT for the proposed CC units should be based on the use of clean fuels, good combustion practices, and an oxidation catalyst. 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 many cases, the level of control depends on how VOC is measured (e.g., 0.33 ppmvd as propane is equivalent to 1 ppmvd as methane), fuel, load, and whether duct burners are in-service (to account for supplemental firing in the HRSG). However, like CO emission limits, most VOC emissions limits for CC units are 2 ppmvd for both fuels (and for gas when duct burners are in-service).

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

- 1.0 ppmvd VOC or less, as methane, 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 or less, as methane, when firing natural gas with duct burners in-service or when firing distillate oil, based on the average of a 3-run stack test using EPA Reference Method 25A.

For gas when the duct burners are not in-service, GPC 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 or never built. 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, GPC 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).

GPC 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 – Combined-Cycle Units VOC Control

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

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

The same resources have been utilized in preparing the Division's PM, CO, SO₂, Greenhouse Gases, H₂SO₄ and NO_x, BACT analyses.

Conclusion – Combined-Cycle Units VOC Control

The technically feasible control technologies for VOC emission control for the combined-cycle units are good combustion practices and an oxidation catalyst. 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 facilities with the most similar combined-cycle units in operation, as well as those listed in the RBLC database, are provided below:

- Alabama Power—Plant Barry (two 744 MW combined-cycle units)
- Jackson Energy Center— (3864.00 MMBtu/hr combined-cycle units)

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

The BACT selection for the Combined-Cycle Units (Emission ID: CT10/DB10 and CT11/DB11) is summarized below in Table 4-4:

Table 4-4: BACT Summary for the Combined-Cycle Units

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
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 2.0 ppmvd VOC, as methane, corrected to 15% O ₂ , duct-burner in-service	3-Run Stack Test EPA Reference Method 25A
	Distillate Oil		2.0 ppmvd VOC, as methane, corrected to 15% O ₂	3-Run Stack Test EPA Reference Method 25A

Combined-Cycle (Emission IDs: CT10/DB10 and CT11/DB11) – 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 – Combined-Cycle Electrical Generating Units

PM emissions from the proposed CC units include both filterable and condensable particles.⁽²⁰⁾ 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 -- Combined Cycle Electrical Generating Units (Step 1)

GPC reviewed PM 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 available in Appendix D, Tables D-17 through D-20 of the application. 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.⁽²¹⁾ 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 low level of PM emissions. Therefore, only the use of fuels with inherently low sulfur content and good combustion practices are considered further.

²⁰ 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 GPC uses the term “PM,” it is meant to include both PM₁₀ and PM_{2.5} unless otherwise noted.

²¹ When EPA originally proposed national standards for CT units in NSPS Subpart GG, EPA stated that “particulate emissions from stationary gas turbines are minimal” and noted that add-on controls for PM are not typically installed on CT units and are cost prohibitive. See 44 Fed. Reg. 52792, 52798 (Sept. 10, 1979); EPA, Standards Support and 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. 8314, 8321 (Feb. 18, 2005). At the time, EPA also noted that no CT units permitted since 2003 utilized add-on controls.

Elimination of Technically Infeasible PM Control Options – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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 GPC'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. GPC 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 Method 5 and 202; and
- Total PM, containing filterable and condensable PM, equal to or less than 0.00135 lb/MMBtu, when firing distillate oil, based on the average of a 3-run stack test using EPA Reference Method 5 and 202.

The proposed PM BACT reflect approximately 0.002 lb/MMBtu filterable PM when firing gas, 0.01 lb/MMBtu when firing distillate oil, and fuel 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).

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, GPC 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).⁽²²⁾

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

EPD Review – Combined-Cycle Units Particulate Matter, Particulate Matter Less than 10 Microns (PM₁₀), and Particulate Matter Less than 2.5 Microns (PM_{2.5}) Emissions

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

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

The same resources have been utilized in preparing the Division's NO_x, CO, SO₂, Greenhouse Gases, H₂SO₄ and VOC BACT analyses.

The Division agrees that pipeline quality natural gas and distillate oil represents BACT control technology for PM/PM₁₀/ PM_{2.5}.

Conclusion – Combined-Cycle Units Particulate Matter, Particulate Matter Less than 10 Microns (PM₁₀), and Particulate Matter Less than 2.5 Microns (PM_{2.5}) Emissions

After completing the review, no add-on control options were identified. Most of the RBLC database BACT limits were for different combustion turbine types, and size, therefore the limits were not comparable for the facility's combustion turbines. Many facilities reviewed during the RBLC review did not have any add-on control options listed, but instead use good combustion practices and clean fuels as BACT. Thus, the technically feasible control technologies for PM/PM₁₀/PM_{2.5} emission control for the combined-cycle units are use of clean fuels with inherently low sulfur content and good combustion practices. Conventional add-on controls, such as baghouses and electric precipitators have not been applied to combustion turbines and would be technically infeasible since, in the BACT context, these emission controls have no real potential to reduce emissions from the proposed combined-cycle units (Emission ID: CT10/DB10 and CT11/DB11). The use of clean fuels inherently low in sulfur content results in a low level of PM emissions and therefore the combination of clean fuels and good combustion practices are the demonstrated and technically feasible options to be considered for this Project.

The Division agrees with the proposed limits for PM BACT. To account for total PM from each combined-cycle unit (Emission ID: CT10/DB10 and CT11/DB11) when firing natural gas or distillate oil, the Division has decided to include the facility requested limit of 0.0045 lb/MMBtu, when firing natural gas, and 0.0135 lb/MMBtu, when firing distillate oil.

²² 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/renewable-energy/documents/RetirementFossilFuels/StonewallPermit.pdf>.

Table 4-5: BACT Summary for the Combined-Cycle Units

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM	Natural Gas	Low Sulfur Content Fuels and Good Combustion Practices	0.0045 lb/MMBtu	3-Run Stack Test EPA Reference Methods 5 and 202
	Distillate Oil		0.0135 MMBtu/hr	

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – Sulfuric Acid Mist (SAM) 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 sulfuric acid mist (SAM) 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 SAM.

SAM Formation – Combustion Turbines

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 -- Combined Cycle Electrical Generating Units (Step 1)

GPC reviewed SAM 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 available in Appendix D, Tables D-21 through D-22 of the application. 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.

The only potentially available control option for SAM emissions from the proposed CC units is use of fuels with inherently low sulfur content. Similar to PM, 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 combustion turbines because the use of fuels with inherently low sulfur content results in a low level of SAM emissions (approximately 0.2 ppmvd in the exhaust gas).

Elimination of Technically Infeasible SAM Control Options – Combined-Cycle Electrical Generating Units (Step 2)

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

Summary and Ranking of Remaining PM Controls – Combined-Cycle Electrical Generating Units (Step 3)

No ranking of control options is required, as use of clean fuels is the only available and technically feasible control options for SAM emissions from the proposed CC units.

Evaluation of Most Stringent PM Controls – Combined-Cycle Electrical Generating Units (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 SAM control options is required.

Selection of Emission Limits for SAM BACT (Step 5)

Based on GPC’s review, SAM BACT for the proposed CC units should be based on use of fuels with inherently low sulfur content. Therefore, GPC 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 SAM BACT for the proposed CC units. The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

EPD Review – Combined-Cycle Units SAM

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

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

The same resources have been utilized in preparing the Division’s NOx, PM, CO, SO2, Greenhouse Gases, and VOC BACT analyses.

The Division agrees that pipeline quality natural gas and distillate oil with a sulfur content less than 15 ppm, by weight, represents BACT control technology for H2SO4.

Conclusion – Combined-Cycle Units SAM

After completing the review, no add-on control options were identified. Most of the RBLC database BACT limits were for different combustion turbine types, and size, therefore the limits were not comparable for the facility’s combustion turbines. Facilities reviewed during the RBLC review did not have any add-on control options listed, but instead listed use of clean fuels inherently low in sulfur content as BACT. The technically feasible control technologies for H2SO4 emission control for the combined-cycle units is use of clean fuels with inherently low sulfur content. Conventional add-on controls, such as baghouses, have not been applied to combustion turbines and would be technically infeasible since, in the BACT context, these emission controls have no real potential to reduce emissions from the proposed combined-cycle units (Emission ID: CT10/DB10 and CT11/DB11). The use of clean fuels inherently low in sulfur content results in a low level of H2SO4 emissions and therefore use of clean fuels is the demonstrated and technically feasible option to be considered for this Project.

Table 4-6: BACT Summary for the Combined-Cycle Units

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
H2SO4	Natural Gas	Low Sulfur Content Fuels	Natural Gas, 0.5 grains sulfur/100 scf	Fuel Supplier Documentation
	Distillate Oil		15 ppm sulfur	

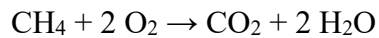
Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – Greenhouse Gases – CO₂ Emissions

Applicant's Proposal

This section contains a high-level review of pollutant formation and possible control technologies for the combustion turbine systems. Though the primary GHG emission from natural gas and fuel oil combustion in the combustion turbine systems is CO₂, GHG BACT is discussed separately for CH₄ and N₂O.

Greenhouse Gases – CO₂ Formation – Combined-Cycle Electrical Generating Units

GHG emissions that result from combustion include carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O).⁽²³⁾ Carbon dioxide 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 necessary to produce heat and are not a byproduct caused by impurities in the fuel or by incomplete combustion.

Identification of Greenhouse Gases – CO₂ Control Technologies – Combined-Cycle Electrical Generating Units (Step 1)

As with the other BACT reviews above, GPC reviewed CO₂ 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. 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 D, Tables D-23 and D-24 of the application.

GPC 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,⁽²⁴⁾ although this control option was not included in the final regulations adopted in Subpart

²³ Comparatively very small emissions of CH₄ and N₂O can occur when, for example, some small fraction of the methane in natural gas is not combusted and when nitrogen in combustion (ambient) air reacts with oxygen in the flame zone, respectively.

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

TTTTa. ⁽²⁵⁾ 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. ⁽²⁶⁾ Nonetheless, more solar and energy storage resource procurement and customer programs have been proposed to the Georgia Public Service Commission (PSC) as part of GPC's comprehensive plan to address Georgia's rapidly growing energy needs. This is in addition to over 4,000 MW of renewable resources currently delivering energy to customers today, 480 MW of renewable projects already under contract or development, and 3,700 MW of additional renewable resources already approved by the PSC through 2030.

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 rules 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 are 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 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

²⁵ 40 CFR Part 60, Subpart TTTTa.

²⁶ 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 Generating Company*, 13 E.A.D. 1,23 (EAB 2006); US EPA *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011).

and cost-effectiveness of this control option. ⁽²⁷⁾ Co-firing low-GHG hydrogen is nonetheless evaluated as a potential control option in the 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 geological 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 in the U.S. Circuit Court of Appeals for the D.C. Circuit. ⁽²⁸⁾ This litigation is currently on hold while EPA reconsiders the rule. In reconsidering the rule, EPA has proposed to either (1) repeal NSPS Subpart TTTTa and its predecessor Subpart TTTT or (2) repeal only the standards based on CCS since this control technology has not been adequately demonstrated.

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 – Combined-Cycle Electrical Generating 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 operates on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with CC units.

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

²⁸ *West Virginia v. EPA*, No. 24-1120.

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. 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. 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). Such programs commonly include three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls.

HRSG maintenance is also important. To maximize heat transfer, the tubes within the shell of the unit 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 U.S. Department of Energy (DOE) recently announced \$7 billion in funding to launch 7 Regional Clean Hydrogen Hubs (H2Hubs) across the nation, none of which will be located in Georgia or in the southeastern US.⁽²⁹⁾ Additionally, the U.S. 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). However, the 45V credits and other incentives may be phased out or eliminated as part of President Trump's tax proposal, causing uncertainty for project development.⁽³⁰⁾ GPC is unaware of any plans to build out the significant infrastructure necessary to make low-GHG hydrogen a commercially available control option. Moreover, even if there were sufficient supply of low-GHG hydrogen 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.⁽³¹⁾ Thus, low-GHG hydrogen is not an available control option and therefore cannot be an applicable control option for the CC units.

Due in part to its lack of availability, hydrogen co-firing remains an emerging technology that has not been demonstrated in practice. Hydrogen can only be co-fired with natural gas because turbine manufacturers have indicated that hydrogen cannot be co-fired with distillate oil. To date, there have been a handful of known test burns of hydrogen blended with natural gas in CTs, including at one of the units at GPC's McDonough-Atkinson Steam-Electric Generating Plant (Plant McDonough). However, most, if not all, of these test burns were conducted for short periods of time using temporary blending systems.⁽³²⁾ Moreover, the test burns that have been conducted used hydrogen that would not qualify as low-GHG hydrogen and therefore did not result in any meaningful reduction in overall GHG emissions. Since these test burns were only temporary in nature and failed to use low-GHG hydrogen, the tests do not suggest that this control option is applicable. According to EPA guidance, applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations."⁽³³⁾

²⁹ <https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations>.

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

³¹ The pipeline specification is 980 Btu/scf HHV. See Transcontinental Gas Pipe Line Company, LLC, FERC Gas Tariff, Fifth Revised Volume No. 1, Part IV - General Terms and Conditions, Section 3 – Quality, 3(b). Blending 30% low-GHG hydrogen with natural gas results in a heating value of approximately 810 Btu/scf. However, the pipeline specification applies to the gas offered at the point of delivery (e.g., just upstream of the point of injection), making direct injection of hydrogen impossible.

³² For example, the short-term test burn at Plant McDonough was conducted at a maximum of approximately 20% hydrogen co-firing by volume for less than a full hour. The test was conducted on a single train of a 2-on-1 combined-cycle unit and required significant on-site oversight and involvement by the OEM.

³³ U.S. EPA, *Draft New Source Review Workshop Manual*, at B.11 (Oct. 1990).

- Since hydrogen co-fired 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, and storage-- must be technically feasible. The integrated suite of components must be also technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the units.⁽³⁴⁾ Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

Capture and Compression

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 combine-cycle combustion turbines. In CTs, whether in simple- 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, along 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.⁽³⁵⁾

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

³⁴ U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 35-36 (March 2011).

³⁵ 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 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.

continuous successful operation, as would be required for a typical power plant.³⁶ 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.

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.³⁷ 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.”

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 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. There are no existing or planned

³⁶ <https://ieefa.org/resources/carbon-capture-boundary-dam-3-still-underperforming-failure>;
<https://www.reuters.com/article/business/environment/problems-plagued-us-co2-capture-project-before-shutdown/document-idUSKCN2523K7/>

³⁷ The permit does not identify CCS as BACT for the facility. Additionally, 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.

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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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. Although technical infeasibility of CCS for control of CO₂ from CCS has been thoroughly evaluated as established herein, and therefore an analysis of cost-effectiveness is unnecessary, GPC recognizes that some recent GHG applications for combined-cycle units have included an economic analysis of CCS, and GPC has reviewed the results of those evaluations. In the analyses of which GPC is aware that have been conducted for other facilities, the average cost of removal per ton of CO₂ calculated for CCS in combined-cycle configurations has exceeded \$100 per ton removed, which has been deemed cost-ineffective in all cases.

Selection of BACT for Greenhouse Gases – CO₂-- Combined-Cycle Electrical Generating Units (Step 5)

Based on GPC's 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 D, Tables D-23 and D-24 of the application, 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 GPC's review of the search results of 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.

- 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. ⁽³⁸⁾
- 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. ⁽³⁹⁾ 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 to 1,340 lb CO₂/MWh-gross when separate limits apply depending on the fuel being burned. ⁽⁴⁰⁾ 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 to 1,000 lb CO₂/MWh-gross, where the upper bound is the emission limit in Subpart TTTT. ⁽⁴¹⁾
- The potentially applicable regulations in Subpart TTTT establish a "sliding-scale" emission standard which, for large CTs, range 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, GPC proposes the following as CO₂ BACT:

- 905 lb CO₂e/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. ⁽⁴²⁾ 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 as summarized below.

Compliance with the proposed GHG BACT limit will be demonstrated by continuously monitoring heat input according to 40 CFR Part 75, Appendix D, and using emission factors to calculate monthly emissions. The emission factor for CO₂ will be based on 40 CFR Part 98, Table C-2 ⁽⁴³⁾

³⁸ 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.

³⁹ 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).

⁴⁰ 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 38.

⁴¹ 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.

⁴² 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.

⁴³ Emission factors are from 40 CFR Part 98 in 78 Federal Register at 71952, November 29, 2013.

and the current global warming potentials in 40 CFR Part 98, Table A-1 (1, 28, and 265 for CO₂, CH₄, and N₂O, respectively).⁽⁴⁴⁾

EPD Review – Combined-Cycle Greenhouse Gases – CO₂ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO₂ BACT analysis and used the following resources and information:

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

The same resources have been utilized in preparing the Division’s NO_x, PM, CO, SO₂, H₂SO₄, and VOC BACT analyses.

The Division agrees that pipeline quality natural gas and distillate oil represents BACT control technology for CO₂.

Conclusion – Combined-Cycle Greenhouse Gases – CO₂ Control

After completing the review, no add-on control options were identified. Most of the RBLC database BACT limits were for different combustion turbine types and size, therefore the limits were not comparable for the facility’s combustion turbines. Facilities reviewed during the RBLC review did not have any add-on control options listed, but instead listed a variation of use of clean fuels, efficient design, good combustion, operating, and maintenance practices as BACT. The technically feasible control technologies for CO₂ emission control for the combined-cycle units is use of clean fuels with inherently low sulfur content, good combustion, operating, and maintenance practices, and efficient design.

Table 4-7: BACT Summary for the Combined-Cycle Units

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Natural Gas	Clean/Low-Emitting Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices	905 lb CO ₂ e/MWh-gross	12-Month Rolling Average	Continuous Monitoring of Heat Input according to 40 CFR 75 Calculation Procedures
	Distillate Oil				

⁴⁴ Global Warming Potentials for GHGs are from amendments to 40 CFR Part 98 in 89 Federal Register at 31802, April 25, 2024.

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – Greenhouse Gases – CH₄ Emissions

Applicant’s Proposal

For the proposed CC 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 Formation – Combined-Cycle Electrical Generating Units

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

Identification of Greenhouse Gases – CH₄ Control Technologies – Combined-Cycle Electrical Generating Units (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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating Units (Step 4)

The top control option 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-- Combined-Cycle Electrical Generating 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 of CH₄ 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 – Combined-Cycle 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 – Combined-Cycle Greenhouse Gases – CH₄ Control

Refer to the previous section for the GHG conclusion.

Combined-Cycle (Emission ID: CT10/DB10 and CT11/DB11) – 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 Formation – Combined-Cycle Electrical Generating Units

N₂O is a component of NO_x, which is formed through 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. However, efforts to reduce NO_x emissions overall can result in higher emissions of the N₂O component of NO_x. Specifically, 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. ⁽⁴⁵⁾ 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. ⁽⁴⁶⁾ Therefore, reductions in NO_x can result in incremental increases in N₂O emissions.

Identification of Greenhouse Gases – N₂O Control Technologies – Combined-Cycle Electrical Generating 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. ⁽⁴⁷⁾ 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.

Elimination of Technically Infeasible Greenhouse Gases – N₂O Control Technologies – Combined-Cycle Electrical Generating Units (Step 2)

⁴⁵ Angello, L., Electric Power Research Institute, Fuel Composition Impacts on Combustion Turbine Operability (March 2006).

⁴⁶ American Petroleum Institute, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (February 2004)

⁴⁷ 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.

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.⁽⁴⁸⁾ 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 – Combined-Cycle Electrical Generating 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 – Combined-Cycle Electrical Generating Units (Step 4)

The top control option is 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 – Combined-Cycle Electrical Generating Units (Step 5)

Good combustion practices are selected as BACT for N₂O emissions from the proposed CC units. GPC 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 of N₂O 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 – Combined-Cycle Greenhouse Gases – N₂O 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 – Combined-Cycle Greenhouse Gases – N₂O Control

Refer to the previous section for the GHG conclusion.

⁴⁸ Emissions of Nitrous Oxide from Combustion Sources, in Progress and Energy and Combustion Science 18(6): pages 529- 552, December 1992. Available at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources.

Cooling Tower BACT Review

Cooling Tower—Particulate Matter (PM) Emissions

Applicant's Proposal

Associated equipment associated with the Project includes:

- Two (2) multi-cell wet mechanical induced draft cooling towers with high efficiency drift eliminators

Particulate Matter Formation – Cooling Towers

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.

Identification of PM Control Technologies --Cooling Towers (Step 1)

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

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.

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

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

Summary and Ranking of Remaining – PM Control Technologies – Cooling Towers (Step 3)

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.

Evaluation of Most Stringent PM Control Technologies – Cooling Towers (Step 4)

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.

Selection of BACT for PM Emissions (Step 5)

Based on GPC's review, PM BACT for the cooling towers should be based on the use of high-efficiency drift eliminators. Based on search results, drift rates for high-efficiency drift eliminators range from 0.0005 to 0.001% of circulating water flow. Based on this information, GPC is

proposing to install drift eliminators with a drift rate of 0.0005% as PM BACT for the cooling towers.

EPD Review – Cooling Tower – PM Control

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

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

Conclusion – Cooling Tower – PM Control

Facilities with cooling towers associated with power generation were used for the review. Based on results, the potential available control option to reduce PM emissions from the cooling towers is high-efficiency drift eliminators, with drift rates ranging from 0.0005 to 0.001% of circulating air flow. Therefore, the Division agrees with the proposed BACT control technology of high-efficiency drift eliminators for the cooling towers.

The Division agrees with the proposed limits for the cooling towers. The cooling towers will be installed with drift eliminators with a drift rate of 0.0005% as PM BACT.

Table 4-8: BACT Summary for the Cooling Towers

Pollutant	Control Technology	Proposed BACT Limit
PM	Drift Eliminators	0.0005% Drift Rate

Fuel Gas Heaters (WBH1 – WBH2) – BACT Review

Fuel Gas Heaters (WBH1 – WBH2) – NO_x Emissions

Applicant's Proposal

Associated equipment associated with the Project includes:

- Two (2) natural gas-fired water bath type fuel gas heaters with ultra-low NO_x burners with a maximum heat input of approximately 8.61 MMBtu/hr (each).

NO_x Formation – Heaters

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

Identification of NO_x Control Technologies – Heaters (Step 1)

GPC searched RBLC and considered relevant existing and proposed federal and state emissions standards to identify potential control options for NO_x emissions from the proposed fuel gas heaters. Generally, NO_x emissions from fuel burning equipment can be controlled through two types of emission control strategies: combustion controls and add-on controls. Combustion controls address thermal NO_x directly by reducing peak flame temperature by, for example, staging combustion and/or recirculating flue gas to reduce the oxygen content of the combustion air. Add-on controls employ various strategies to reduce NO_x emissions to water and nitrogen, which often includes the use of reagents in the presence of a catalyst. Based on the RBLC search results provided in Appendix D of the application, Table D-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 NO_x burners), as BACT. Add-on controls potentially applicable to the proposed fuel gas heaters include SCR, selective non-catalytic reduction (SNCR), and non-selective catalytic reduction (NSCR).

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

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

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

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

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

- SCR – Injection of nitrogen-based reagent (e.g., ammonia or urea) in the presence of a catalyst

- SNCR – Similar to SCR, except no catalyst is used and higher operating temperatures are required
- NSCR – Catalyst reaction without use of a reagent in exhaust gas with low oxygen content

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

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

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

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

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

Selection of Emission Limits for NO_x BACT (Step 5)

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

GPC 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 (40 CFR Part 63, Subpart DDDDD).⁽⁴⁹⁾ 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

⁴⁹ 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.

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

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

The same resources have been utilized in preparing the Division’s PM, SO₂, CO, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Heaters NOx Control

Based on the RBLC search and review, the technically feasible control technologies for NOx emission control for the fuel gas heaters are use of natural gas, good combustion practices, and ultra-low NOx burners. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels, good combustion practices, and ultra-low NOx burners as BACT practices. Therefore, The Division agrees with the proposed BACT control technology of use of natural gas, good combustion practices, and ultra-low NOx burners.

Table 4-9: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
NOx	Natural Gas	Natural Gas, Ultra-Low NOx Burners and Good Combustion Practices	Exclusive use of natural gas; 9 ppmvd, corrected to 3% O ₂ , or 0.011 lb/MMBtu	Biennial Tune-Up

Fuel Gas Heaters (WBH1 – WBH2) – SO₂ Emissions

Applicant's Proposal

SO₂ Formation – 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 – Heaters (Step 1)

For SO₂, GPC also searched the RBLC to identify potential control options for the proposed fuel gas heaters. The result of this search is summarized in Appendix D, Table D-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 fuel gas 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 low level of emissions.

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

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

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

No ranking of control options is required, as use of fuels with inherently low sulfur content and good combustion practices are the only available and technically feasible control options for SO₂ emissions from the proposed fuel gas heaters.

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

The top control options are being proposed for SO₂ emissions from the proposed fuel gas heaters. Therefore, no evaluation of the SO₂ control options is required.

Selection of Emission Limits for SO₂ BACT (Step 5)

Based on GPC's review, SO₂ BACT for the proposed fuel gas heaters should be based on use of fuels with inherently low sulfur content and good combustion practices. GPC proposes to exclusively fire pipeline quality natural gas in these heaters.

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

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

Conclusion – Heaters SO₂ Control

Based on the RBLC search and review, the technically feasible control technologies for SO₂ emission control for the fuel gas heaters are use of clean fuels inherently low in sulfur content and good combustion practices. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels and good combustion practices as BACT practices. Therefore, The Division agrees with the proposed BACT control technology of use of good combustion practices, and use of clean fuels with inherently low sulfur content.

Table 4-10: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
SO ₂	Natural Gas	Low Sulfur Content Fuel; Good Combustion Practices	Exclusive Use of Natural Gas	Fuel Records

Fuel Gas Heaters (WBH1 – WBH2) – CO Emissions

Applicant's Proposal

CO Formation – Heaters

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

Identification of CO Control Technologies – Heaters (Step 1)

GPC searched RBLC and considered relevant existing and proposed federal and state emissions standards to identify potential control options for CO emissions from the proposed fuel gas heaters. Like NO_x, CO emissions from fuel-burning equipment can be controlled through two types of emission control strategies: good combustion practices and add-on controls. For sources such as the proposed fuel gas heaters, there is typically a trade-off between emissions of NO_x and CO. For example, higher combustion temperatures and residence times may lead to more complete fuel combustion and thus lower CO emissions, but these control techniques may result in excessive NO_x emissions. Good combustion practices strive to optimize emissions for both pollutants. Add-on controls may employ various types of catalysts to oxidize CO emissions to CO₂. Based on the RBLC search results provided in Appendix D of the application, Table D-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 fuel gas heaters include oxidation catalysts.

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

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible. Available combustion controls for such units are typically offered with performance guarantees for CO emissions.

Oxidation Catalysts

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. GPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. As discussed above, only combustion controls for NO_x emissions from small process heaters are commercially available. Therefore, oxidation catalysts are not technically feasible.

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

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

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

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

Selection of Emission Limits for CO BACT (Step 5)

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

GPC 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 (40 CFR Part 63, Subpart DDDDD).⁽⁵⁰⁾ 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM, NO_x, SO₂, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Heaters CO Control

Based on the RBLC search and review, the technically feasible control technologies for CO emission control for the fuel gas heaters are good combustion practices and the exclusive use of natural gas. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels and good combustion practices as BACT practices. CO emission limits for natural gas-fired fuel gas heaters with a heat input rating less than 10 MMBtu/hr ranges from 0.037 to 0.110 lb/MMBtu, however only Tennessee Valley Authority — Colbert Combustion Turbine Plant (AL-0239) had emission limits for both NO_x and CO. The Division agrees with the proposed BACT control technology of use of good combustion practices and natural gas.

⁵⁰ *Id.*

Table 4-11: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
CO	Natural Gas	Natural Gas, Good Combustion Practices	Exclusive use of natural gas; 100 ppmvd, corrected to 3% O ₂ , or 0.074 lb/MMBtu	Biennial Tune-Up

Fuel Gas Heaters (WBH1 – WBH2) – VOC Emissions

Applicant's Proposal

VOC Formation – Heaters

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

Identification of VOC Control Technologies – Heaters (Step 1)

GPC searched RBLC and considered relevant existing and proposed federal and state emissions standards to identify potential control options for VOC emissions from the proposed fuel gas heaters. Like CO, VOC emissions from fuel-burning equipment have similar considerations and can be controlled through good combustion practices and add-on controls. Based on the RBLC search results provided in Appendix D of the application, Table D-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 fuel gas heaters include oxidation catalysts.

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

Use of Clean Fuels and Good Combustion Practices

Use of natural gas and good combustion practices are inherent to the Project and technically feasible. Available combustion controls for such units are typically offered with performance guarantees for VOC emissions.

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. GPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. Therefore, oxidation catalysts are not technically feasible.

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

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

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

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

Selection of Emission Limits for VOC BACT (Step 5)

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

Vendor information indicates that VOC emissions from the proposed fuel gas heaters should not exceed 20 ppmvd (as methane), corrected to 3% O₂, or 0.010 lb/MMBtu. However, instead of a numerical BACT limit, GPC is proposing the exclusive use of natural gas and optimizing emissions of CO during biennial tune-ups required by the Industrial Boiler MACT (40 CFR Part 63, Subpart DDDDD) as BACT.

EPD Review – Heaters VOC Control

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

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

The same resources have been utilized in preparing the Division's PM, NO_x, SO₂, Greenhouse Gases, and CO BACT analyses.

Conclusion – Heaters VOC Control

Based on the RBLC search and review, the technically feasible control technologies for VOC emission control for the fuel gas heaters are good combustion practices and the exclusive use of natural gas. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels and good combustion practices as BACT practices. VOC emission limits for natural gas-fired fuel gas heaters with a heat input rating less than 10 MMBtu/hr ranges from 0.005 to 0.050 lb/MMBtu. However, vendor information indicates that VOC emissions from the proposed fuel gas heaters should not exceed 20 ppmvd (as methane), corrected to O₂%, or 0.010 MMBtu/hr. Instead of a numerical BACT limit, GPC is proposing the exclusive use of natural gas and optimizing emissions of CO during biennial tune-ups required by Boiler MACT, 40 CFR Part 63 Subpart DDDDD as BACT. The Division agrees with the proposed BACT control technology of use of good combustion practices and natural gas.

Table 4-12: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
VOC	Natural Gas	Natural Gas; Good Combustion Practices	Exclusive Use of Natural Gas	Biennial Tune-Up for CO

Fuel Gas Heaters (WBH1 – WBH2) – Particulate Matter (PM) Emissions

Applicant's Proposal

PM Formation – Heaters

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

Identification of PM Control Technologies – Heaters (Step 1)

GPC searched RBLC and considered relevant existing and proposed federal and state emissions standards to identify potential control options for PM emissions from the proposed fuel gas heaters. Based on the RBLC search results provided in Appendix D of the application, Table D-30, no add-on control options were identified. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas-fired fuel-burning equipment like the fuel gas heaters since combustion of natural gas inherently results in low levels of emissions.⁽⁵¹⁾ Instead, many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices as BACT. Accordingly, these control options are the only options considered further.

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

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

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

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

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

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

Selection of Emission Limits for PM BACT (Step 5)

Based on GPC's review, PM BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, PM

⁵¹ 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. at 24798 (June 9, 1989).

emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.007 to 0.010 lb/MMBtu.

Vendor information indicates that PM emissions from the proposed fuel gas heaters will be less than 0.005 lb/MMBtu.

EPD Review – Heaters PM Control

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

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

The same resources have been utilized in preparing the Division’s VOC, NOx, SO₂, Greenhouse Gases, and CO BACT analyses.

Conclusion – Heaters PM Control

Based on the RBLC search and review, the technically feasible control technologies for PM emission control for the fuel gas heaters are good combustion practices and the exclusive use of natural gas. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels and good combustion practices as BACT practices. PM emission limits for natural gas-fired fuel gas heaters with a heat input rating less than 10 MMBtu/hr ranges from 0.007 to 0.010 lb/MMBtu. Vendor information indicates that PM emissions from the proposed fuel gas heaters will be less than 0.005 lb/MMBtu. However, instead of a numerical BACT limit, GPC is proposing exclusive use of natural gas and good combustion practices as BACT. The Division agrees with the proposed BACT control technology of use of good combustion practices and natural gas.

Table 4-13: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM	Natural Gas	Low Sulfur Content Fuel	Exclusive Use of Natural Gas; Good Combustion Practices	Fuel Records

Fuel Gas Heaters (WBH1 – WBH2) – Greenhouse Gases (GHG) Emissions

Applicant's Proposal

GHG Formation – Heaters

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

Identification of GHG Control Technologies – Heaters (Step 1)

Based on the RBLC search results provided in Appendix D of the application, Table D-31, no add-on control options were identified that would reduce GHG emissions from the proposed fuel gas heaters. Instead, many facilities listed some variation of use of clean fuels and good combustion practices as BACT for GHG emissions.

CCS should not be considered as a potentially available control option for sources with insignificant GHG emissions. 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 steams, consistent with past EPA guidance.⁽⁵²⁾ Accordingly, use of natural gas and good combustion practices are the only potentially available control options for GHG emissions from the proposed fuel gas heaters.

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

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

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

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

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

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

Selection of Emission Limits for GHG BACT (Step 5)

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

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

EPD Review – Heaters GHG Control

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

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

The same resources have been utilized in preparing the Division’s VOC, NOx, SO2, PM, and CO BACT analyses.

Conclusion – Heaters GHG Control

Based on the RBLC search and review, the technically feasible control technologies for GHG emission control for fuel gas heaters are good combustion practices and the exclusive use of natural gas. Many facilities, for heaters of varied sizes, list a variation of use of clean fuels and good combustion practices as BACT practices. The Division agrees with the proposed BACT control technology of use of good combustion practices and natural gas.

Table 4-14: BACT Summary for the Fuel Gas Heaters (Emission ID: WHB1 and WB2)

Pollutant	Fuel	Control Technology	Proposed BACT Limit	Compliance Determination Method
GHG	Natural Gas	Clean/Low-Emitting Fuels	Exclusive Use of Natural Gas	Fuel Records

Distillate Oil Storage Tanks BACT Review

Distillate Oil Storage Tanks — VOC Emissions

Applicant's Proposal

Characterization of Emissions – Tanks

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 – Tanks (Step 1)

GPC searched RBLC and considered relevant existing and proposed federal and state emission standards to identify potential control options for VOC emissions from the proposed diesel storage tank. Based on the search results provided in Appendix D of the application, Table D-32, no additional 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.⁽⁵³⁾ 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 would not apply to the proposed diesel storage tank because the vapor pressure of stored liquid (distillate oil) is so low. GPC has nonetheless evaluated technical feasibility and other factors for these control options, along with use of submerged filling and tank design.

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

Use of submerged filling and light or reflective tank surface colors are inherent to the Project and technically feasible. While use of light or reflective tank surface colors is technically feasible, there is no need to consider this control option since the tank roof and shell will be fully insulated.⁽⁵⁴⁾

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

⁵⁴ 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

GPC did not identify a case where the remaining control options have been installed and operated successfully on the type of source under review. In prior BACT determinations, EPA affirmed that these control options are generally not effective for controlling low concentrations of VOC generated by diesel storage tanks.⁽⁵⁵⁾ Therefore, use of submerged filling and light or reflective tank surface colors are the only technically feasible control options.

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

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

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

The top control options are being proposed for emissions of VOC from the proposed diesel storage tank. Therefore, no evaluation of the VOC control options is required.⁽⁵⁶⁾

Selection of Emission Limits for VOC BACT (Step 5)

Based on GPC's review, VOC BACT for the proposed diesel storage tanks should be based on the use of submerged filling and fully insulating the tank roof and shell. 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 diurnal temperature changes and fully insulating the tank roof and shell minimizes evaporative losses.

EPD Review – Distillate Oil Storage Tank – VOC Control

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.

⁵⁵ Preliminary Determination & Statement of Basis – Outer Continental Shelf Air Permit Modification OCS-EPAR4012-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, at 29. https://www.epa.gov/sites/default/files/2015-07/documents/2014_07_09_statoil_pd_0.pdf.

⁵⁶ 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 (October 4, 2023). 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.

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

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

Conclusion – Distillate Oil Storage Tank – VOC Control

Based on the RBLC search and review, many facilities, for distillate oil storage tanks of varied sizes, list a variation of work practice standards such as tank design, submerged filling, external tank color, etc. as BACT practices. In comparing the facility to other similar units, the Division agrees with the proposed BACT to use of a submerged fill pipe and fully insulating the tank roof and shell.

Table 4-15: BACT Summary for the Distillate Oil Storage Tanks (Emission ID: T01 and T02)

Pollutant	Tank Content	Control Technology	Proposed BACT Limit	Compliance Determination Method
VOC	Distillate Oil	Submerged Filing and Fully Insulated Tank Roof/Shell	Tank Design	Tank Design

Emergency Generators (Emission ID: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) BACT Review

Emergency Generators (Emission ID: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) Background

Associated equipment associated with the Project includes:

- Two (2) Tier 2 1,500 kW emergency generators
- One (1) Tier 2 500 kW emergency generator
- One (1) Tier 3 350 hp fire water pump engine

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) and are the basis for the current Tier 4 standards. EPA began requiring use of ultra-low sulfur diesel (ULSD) fuel in 2010 since catalytic NO_x controls required its use to be effective.

NSPS Subpart IIII requires owners and operators of stationary CI internal combustion engines (ICE) that use diesel fuel to purchase engines certified to meet the emission standard applicable to the engine category for the same model year and maximum engine power as well as to use ULSD, with limited exceptions. The proposed emergency generator must be certified to Tier 2 standards, while the fire water pump engine must be certified to Tier 3 standards.⁽⁵⁷⁾ 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 engine are those that are included with the purchase of an emergency generator certified to Tier 2 standards, a fire water pump engine certified to Tier 3 standards, or a non-emergency engine certified to Tier 4 standards and operated as if it were an emergency generator or fire water pump engine.

⁵⁷ 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) for fire

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) — NO_x Emissions

Applicant's Proposal

NO_x Formation – Engines

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

Identification of NO_x Control Technologies – Engines (Step 1)

As discussed above, available control options for NO_x emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in Appendix D of the application, Table D-33, there are several cases in which the purchase of a Tier 4 engine was listed as BACT for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

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

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.⁽⁵⁸⁾ Therefore, Tier 4 is also considered technically feasible.

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

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

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

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for NO_x to be between ~\$240,000 and \$400,000 per ton when applied to emergency engines with similar power ratings.⁽⁵⁹⁾ The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours.

⁵⁸ 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-2011present.xlsx>.

⁵⁹ Cost per Ton for NSPS for Stationary CI ICE, Table 5, June 2004, available at https://www.epa.gov/sites/default/files/2014-02/documents/6-9-05_cost_per_ton_ci_nsps.pdf. In Table 4, EPA provides costs for NO_x adsorber technology as low as \$13,500 per ton. However, since this technology is not listed as an aftertreatment device type in use for any Tier 4 certified engine in EPA's annual certification database (column Q), it is presumed that Tier 4 engines that reduce emissions of NO_x at this level of cost-effectiveness when used as emergency engines are not commercially available.

This is true for the proposed emergency generators, which will be operated for a maximum of 200 hours per year pursuant to Rule (mmm) and for the proposed fire water pump engine, which will be operated for a maximum of 500 hours per year. Therefore, purchase of a Tier 4 engine is eliminated from this BACT analysis for both the proposed emergency generator and fire water pump engine.

Selection of Emission Limits for NO_x BACT (Step 5)

NO_x BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase emergency generators 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 – 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's PM₁₀, SO₂, CO, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Engines – NO_x Control

Based on the RBLC search and review for the proposed emergency engines and fire water pump engine, the option of purchasing a Tier 4 non-emergency generator and operating it as if it were an emergency generator or fire water pump engine was determined to be cost-ineffective. However, a variety of facilities listed the purchasing of a Tier 2 emergency generator and a Tier 3 fire water pump as the NO_x BACT. Thus, it will be more technically and economically feasible for the proposed NO_x BACT for the emergency generators and emergency fire water pump to be in compliance with 40 CFR Part 60 Subpart IIII standards.

The Division agrees that NO_x BACT for the emergency generators and emergency fire water pump is the purchase of Tier 2 emergency generators and a Tier 3 fire water pump engine in compliance with NSPS Subpart IIII standards.

Table 4-16: NO_x BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
NO _x	Emergency Generators	Purchase Tier 2 Engine	NSPS Subpart IIII	Comply with NSPS Subpart IIII and Rule (mmm)
	Fire Water Pump Engine	Purchase Tier 3 Engine		

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) — SO₂ Emissions

Applicant's Proposal

SO₂ Formation – Engines

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 USLD are very low due to the low concentration of sulfur compounds in the fuel.

Identification of SO₂ Control Technologies – Engines (Step 1)

As discussed above, EPA requires the use of ULSD in nearly all CI engines and the proposed emergency generators and fire water pump engine will be required to use ULSD for compliance with NSPS Subpart III. Please refer to 40 CFR 60.4207 and 1090.305. Conventional add-on controls are not commercially available. As expected, no control alternatives were identified in the RBLC search results, summarized in Appendix D, Table D-34. The use of ULSD has consistently been determined to be SO₂ BACT for such engines. However, some of these listings also identify efficient combustion or good combustion practices as part of BACT.

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

Use of ULSD is inherent to the Project and technically feasible.

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

No ranking of control options is required, as use of ULSD is the only available and technically feasible control option for SO₂ emissions from the proposed emergency generators and fire water pump engine.

Evaluation of Most Stringent SO₂ Controls – Engines (Step 4)

The top control option is being proposed for SO₂ emissions from the proposed emergency generators and fire water pump engine. Therefore, no further evaluation of the impacts of the control options is required.

Selection of Emission Limits for SO₂ BACT (Step 5)

SO₂ BACT for the proposed emergency generators and fire water pump engine is based on exclusive use of ULSD in compliance with NSPS Subpart III.

EPD Review – Engines – 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

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

Conclusion – Engines – SO₂ Control

Based on the RBLC search and review, most SO₂ BACT determinations listed for the emergency generator engines and fire water pump engine require the use of ULSD. Therefore, it will be technically feasible for the proposed SO₂ BACT for the emergency generators and emergency fire water pump to be in compliance with 40 CFR Part 60 Subpart IIII standards.

The Division agrees that SO₂ BACT for the emergency generators and fire water pump engine is the use of ULSD in compliance with NSPS IIII standards.

Table 4-17: SO₂ BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
SO ₂	Emergency Generators	Ultra-Low Sulfur Diesel	NSPS Subpart IIII	Comply with NSPS Subpart IIII and Rule (mmm)
	Emergency Fire Water Pump Engine	Ultra-Low Sulfur Diesel		

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) - CO Emissions

Applicant's Proposal

CO Formation – Engines

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

Identification of CO Control Technologies – Engines (Step 1)

As discussed above, available control options for CO emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in Appendix D of the application, Table D-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. ⁽⁶⁰⁾

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 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.

⁶⁰ 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 Clearinghouse
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division’s PM₁₀, NO_x, SO₂, Greenhouse Gases, and VOC BACT analyses.

Conclusion – Engines – CO Control

Based on the RBLC search and review, only one CO BACT determination listed for the emergency generator engines and fire water pump engine is purchasing a Tier 4 non-emergency generator and operating it as if it were an emergency generator. However, a variety of facilities listed purchasing a Tier 2 emergency generator and a Tier 3 fire water pump as the CO BACT.

The Division agrees that CO BACT for the emergency generators and fire water pump engine is the purchase of Tier 2 emergency generators and a Tier 3 fire water pump engine in compliance with NSPS IIII standards.

Table 4-18: CO BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
CO	Emergency Generators	Purchase Tier 2 Engine	NSPS Subpart IIII	Comply with NSPS Subpart IIII and Rule (mmm)
	Emergency Fire Water Pump Engine	Purchase Tier 3 Engine		

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) — VOC Emissions

Applicant's Proposal

VOC Formation – Engines

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

Identification of VOC Control Technologies – Engines (Step 1)

As discussed above, available control options for VOC (NMHC) emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in Appendix D of the application, Table D-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 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.⁽⁶¹⁾ The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. This is true for the proposed emergency generator and fire water pump engine, which will be operated for a maximum of 200 and 500 hours per year, respectively. Therefore, Tier 4 is eliminated from this BACT analysis for

⁶¹ US EPA, Alternative Control Techniques Document: Stationary Diesel Engines, Final Report, EPA Contract No. EP-D-07-019, Table 5-5, March 2010.

both the proposed emergency generator and fire water pump engine based on the unreasonable estimated annual cost of control.

Selection of Emission Limits for VOC BACT (Step 5)

VOC BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. GPC will purchase an emergency generator certified to Tier 2 standards and a fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer’s emission-related instructions.

EPD Review – Engines – VOC Control

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

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

The same resources have been utilized in preparing the Division’s PM₁₀, NO_x, SO₂, Greenhouse Gases, and CO BACT analyses.

Conclusion – Engines – VOC Control

Based on the RBLC search and review, several VOC BACT determinations listed for emergency generator engines and fire water pump engine require the purchasing a Tier 4 non-emergency generator and operating it as if it were an emergency generator or fire water pump engine. For the proposed emergency engines and fire water pump engine, this option will not be cost-effective. However, a variety of facilities listed the purchasing a Tier 2 emergency generator and a Tier 3 fire water pump as the VOC BACT. Thus, it will be more technically and economically feasible for the proposed VOC BACT for the emergency generators and emergency fire water pump to be in compliance with 40 CFR Part 60 Subpart IIII standards.

The Division agrees that VOC BACT is the purchase of Tier 2 emergency generators and a Tier 3 fire water pump engine in compliance with NSPS IIII standards.

Table 4-19: VOC BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
VOC	Emergency Generators	Purchase Tier 2 Engine	NSPS Subpart IIII	Comply with NSPS Subpart IIII and Rule (mmm)
	Emergency Fire Water Pump Engine	Purchase Tier 3 Engine		

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) — Particulate Matter (PM) Emissions

Applicant's Proposal

PM Formation – Engines

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

Identification of PM Control Technologies – Engines (Step 1)

As discussed above, in addition to use of ULSD, available control options for PM emissions from the proposed emergency generator and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine, or purchasing a Tier 4 non-emergency engine and operating it as if it were an emergency generator or fire water pump engine. Based on the RBLC search results provided in Appendix D of the application, Table D-37, there were no cases in which Tier 4 was identified as BACT for PM. GPC has nonetheless evaluated technical feasibility and other factors for this control option.

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 III 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.⁽⁶²⁾ The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. 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 engine, which will be

⁶² 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.

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. 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.

EPD Review – Engines – PM Control

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

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

The same resources have been utilized in preparing the Division’s greenhouse gases, NOx, SO2, VOC, and CO BACT analyses.

Conclusion – Engines – PM Control

Based on the RBLC search and review, most PM BACT determinations listed for the emergency generator engines and fire water pump engine is the purchase of a Tier 4 non-emergency generator and operating it as if it were an emergency generator or fire water pump engine. For the proposed emergency engines and fire water pump engine, this option will not be cost-effective. However, a variety of facilities listed the purchasing of Tier 2 emergency generators and a Tier 3 fire water pump as the PM BACT. Thus, it will be more technically and economically feasible for the proposed PM BACT for the emergency generators and emergency fire water pump to be in compliance with NSPS Subpart IIII standards.

The Division agrees that PM BACT is the purchase of Tier 2 emergency generators and a Tier 3 fire water pump engine in compliance with NSPS IIII standards.

Table 4-20: PM BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM	Emergency Generators	Purchase Tier 2 Engine	NSPS Subpart IIII	Comply with NSPS Subpart IIII and Rule (mmm)
	Emergency Fire Water Pump Engine	Purchase Tier 3 Engine		

Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1) — Greenhouse Gases (GHG) Emissions

Applicant's Proposal

GHG Formation – Engines

As with the proposed CC units and fuel gas heaters, GHG emissions that result from the combustion of ULSD in the proposed emergency generators and fire water pump engine 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 D of the application, Table D-38, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generator and fire water pump engine. Instead, many facilities listed some variation of use of clean fuels (natural gas and distillate oil), good combustion practices, and limiting annual operating hours as BACT for GHG emissions.

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

Additionally, CCS should not be considered as a potentially available control option since GHG emissions from the proposed emergency generators and fire water pump engine 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.⁽⁶³⁾ Accordingly, use of ULSD, good combustion practices, and limiting annual operating hours are the only potentially available control options for GHG emissions from the proposed emergency generator and fire water pump engine.

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

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

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

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

⁶³ US EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 32 (March 2011).

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

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

Selection of Emission Limits for GHG BACT (Step 5)

GHG BACT for the proposed emergency generator and fire water pump engine is based on the exclusive use of ULSD as fuel in compliance with NSPS Subpart IIII 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

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

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

The same resources have been utilized in preparing the Division's PM, NO_x, SO₂, VOC, and CO BACT analyses.

Conclusion – Engines – GHG Control

Based on the RBLC search and review, facilities listed some variation of use of clean fuels, good combustion practices, and limiting operating hours as BACT practices for GHG emissions. No add-on control options were identified that would reduce GHG emissions from the engines. The Division agrees the technically feasible control technologies for GHG emission control for the engines is exclusive use of ULSD, in compliance with NSPS IIII standards, and limiting annual operating hours.

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

Table 4-21: GHG BACT Summary for Emergency Generators (Emission IDs: EG1, EG2, and EG3) and Fire Water Pump Engine (Emission ID: FP1)

Pollutant	Engine Type	Control Technology	Proposed BACT Limit	Compliance Determination Method
GHG	Emergency Generators	Ultra-Low Sulfur Diesel	Clean/Low-Emitting Fuels; maximum 200 hours of operation per year, including 100 hrs/yr for maintenance checks and readiness testing, 50 hours of which may be used in non-emergency situations	Comply with NSPS Subpart IIII and Rule (mmm)
	Emergency Fire Water Pump Engine			

Applicant’s Proposal – Summary of Proposed BACT

Table 4-22 summarizes the proposed BACT limits and compliance demonstration methods for each of the Project’s proposed emission units.

Table 4-22. Proposed BACT Emission Limits and Compliance Demonstration Methods

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Averaging Time	Compliance Determination Method
Combined-Cycle Units	NOx	Natural Gas	DLN Combustors, Water Injection, and Selective Catalytic Reduction	2.0 ppmvd NOx, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	4-Hour Rolling Average	NOx CEMS
		Distillate Oil		5.0 ppmvd NOx, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	4-Hour Rolling Average	NOx CEMS
		Both		203.7 tons NOx or less, including periods of startup, shutdown, and fuel switching	12-Month Rolling Average	NOx CEMS
	SO ₂	Natural Gas	Low Sulfur Content Fuels	Natural gas, 0.5 grains sulfur/100 scf Ultra-low sulfur distillate oil	N/A	Fuel Supplier Documentation
	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	24-Hour Rolling Average	CO CEMS
		Distillate Oil		2.0 ppmvd CO, corrected to 15% O ₂ , excluding periods of startup, shutdown, and fuel switching	24-Hour Rolling Average	CO CEMS
		Both		254.7 tons CO or less, including periods of startup, shutdown, and fuel switching	12-Month consecutive period	CO CEMS

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Averaging Time	Compliance Determination Method
	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 2.0 ppmvd VOC, as methane, corrected to 15% O ₂ , duct-burner in-service	N/A	3-Run Stack Test EPA Reference Method 25A
		Distillate Oil		2.0 ppmvd VOC, as methane, corrected to 15% O ₂	N/A	3-Run Stack Test EPA Reference Method 25A
	PM	Natural Gas	Low Sulfur Content Fuels	0.0045 lb/MMBtu	N/A	3-Run Stack Test EPA Reference Methods 5 and 202
		Distillate Oil		0.0135 MMBtu/hr		
	H ₂ SO ₄	Natural Gas	Low Sulfur Content Fuels	Natural Gas, 0.5 grains sulfur/100 scf Ultra-Low Sulfur Distillate Oil	N/A	Fuel Supplier Documentation
		Distillate Oil		15 ppm sulfur		
	GHG	Natural Gas	Clean/Low-Emitting Fuels, Efficient Design, and Good Combustion, Operating, and Maintenance Practices	905 lb CO ₂ e/MWh-gross	12-Month Rolling Average	Continuous Monitoring of Heat Input according to 40 CFR 75 Calculation Procedures
		Distillate Oil				

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Averaging Time	Compliance Determination Method
Fuel Gas Heaters	NOx	Natural Gas	Ultra-Low NOx Burners and Good Combustion Practices	9 ppmvd, corrected to 3% O ₂ , or 0.011 lb/MMBtu	N/A	Biennial Tune-Up
	SO ₂	Natural Gas	Low Sulfur Content Fuel	Exclusive Use of Natural Gas	N/A	Fuel Records
	CO	Natural Gas	Good Combustion Practices	100 ppmvd, corrected to 3% O ₂ , or 0.074 lb/MMBtu	N/A	Biennial Tune-Up
	VOC	Natural Gas	Good Combustion Practices	Exclusive Use of Natural Gas	N/A	Biennial Tune-Up for CO
	PM	Natural Gas	Low Sulfur Content Fuel	Exclusive Use of Natural Gas	N/A	Fuel Records
	GHG	Natural Gas	Clean/Low-Emitting Fuels	Exclusive Use of Natural Gas	N/A	Fuel Records
Distillate Oil Storage Tank	VOC	Distillate Oil	Submerged Filing and Fully Insulated Tank Roof/Shell	Tank Design	N/A	Tank Design
	NOx	Distillate Oil	NSPS Subpart III	Purchase Tier 2 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Averaging Time	Compliance Determination Method
Emergency Generators	SO ₂	Distillate Oil	NSPS Subpart III	Ultra-Low Sulfur Diesel	N/A	Comply with NSPS Subpart III and Rule (mmm)
	CO	Distillate Oil	NSPS Subpart III	Purchase Tier 2 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	VOC	Distillate Oil	NSPS Subpart III	Purchase Tier 2 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	PM	Distillate Oil	NSPS Subpart III	Purchase Tier 2 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	GHG	Distillate Oil	NSPS Subpart III	Clean/Low-Emitting Fuels; maximum 200 hours of operation 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 Subpart III and Rule (mmm)
	NO _x	Distillate Oil	NSPS Subpart III	Purchase Tier 3 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	SO ₂	Distillate Oil	NSPS Subpart III	Ultra-Low Sulfur Diesel	N/A	Comply with NSPS Subpart III and Rule (mmm)
	CO	Distillate Oil	NSPS Subpart III	Purchase Tier 3 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Averaging Time	Compliance Determination Method
Fire Water Pump Engine	VOC	Distillate Oil	NSPS Subpart III	Purchase Tier 3 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	PM	Distillate Oil	NSPS Subpart III	Purchase Tier 3 Engine	N/A	Comply with NSPS Subpart III and Rule (mmm)
	GHG	Distillate Oil	NSPS Subpart III	Ultra-Low Sulfur Diesel, maximum of 500 hours/yr of operation	N/A	Comply with NSPS Subpart III and Rule (mmm)

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 combined-cycle unit. 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 KKKKa. Compliance with the Subpart KKKKa emissions standards will be verified based on CEMS data. Pursuant to 40 CFR 60.4333a(a), the combined-cycle units, 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.⁽⁶⁴⁾ 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 Relative Accuracy Test Audit (RATA) to the NO_x emission limit under this subpart.⁽⁶⁵⁾ Per 40 CFR 60.4340a(a)(2), 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 KKKKa NO_x standards. The Plant CCs will operate without water injection during natural gas combustion. Water injection will be required for fuel oil combustion.

40 CFR 60.4335a 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 KKKKa specific requirements for a CEMS are detailed in 40 CFR 60.4345a, including an option to rely on a CEMS installed and certified per Appendix A to Part 75. Therefore, the use of a NO_x CEMS meeting the requirements of 40 CFR Part 75 Appendix A will be sufficient for NSPS Subpart KKKKa 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 CC of 203.7 tpy on a rolling 12-month basis to ensure the minimization of emissions during startup/shutdown periods.

Requirements for SO₂

NSPS Subpart KKKKa 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

⁶⁴ 40 CFR 60.4340a(b), 40 CFR 60.4405

⁶⁵ 40 CFR 60.4405a

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.

In order to demonstrate compliance with the SO₂ emission limit, the Permittee can opt to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by the Division. The total sulfur content of fuel oil combusted in the combustion turbine must be determined by flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.

Or, per 40 CFR 60.4333a(d)(3), the Permittee may elect to satisfy the sulfur content requirements by using natural gas and fuel oil which are demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO₂. This demonstration can be made by using valid purchase contracts, tariffs sheets, or transportations contracts, or by using representative fuel sampling data. In keeping with the provisions of 40 CFR 60.4372a, 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. SO₂ mass emissions from Combustion Turbines CT10 and CT11 firing distillate oil 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 CO

To reasonably assure compliance with the BACT CO emission limitations, the Permittee shall install, calibrate, operate, and maintain a CO CEMS for periodic monitoring of CO emissions from each combined-cycle unit. Initial compliance with the BACT CO emission limitations for each combined-cycle unit must be demonstrated by using the CEMS data during the initial performance test for VOC. For each of the combined-cycle unit (with combustion turbines CT10 and CT11), separate tests must be conducted while burning natural gas and ultra-low sulfur diesel fuel. The proposed primary BACT limits 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 combined-cycle unit of 257.4 tpy to ensure the minimization of emissions during startup/shutdown periods.

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. Performance testing shall be conducted every five years (no more than 61 calendar months following the previous performance test). The CO emissions during each test, determined by using the CO CEMS, shall be included with the test report.

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 distillate oil, the Division concurs that no monitoring of VOC will be required except for continuous monitoring of CO emissions as a surrogate.

Requirements for Particulate Matter and Opacity

Natural gas and USLD fuel are both low-ash fuels. Consequently, the Division believes each combined-cycle unit 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 5, Method 202, and Method 9, respectively. Method 9 also will be the basis for periodic monitoring of visible emissions, when the Division deems necessary. With the use of good combustion practices, pipeline quality natural gas, and USLD fuel, the Division concurs, that no monitoring of PM will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for GHG

Compliance with the proposed GHG BACT limit will be demonstrated by monitoring fuel consumption and performing calculations. The facility will have conditions in the permit that require monthly recordkeeping of natural gas and fuel oil usage in each combustion turbine. Specifically, the monthly CO_{2e} emissions will be calculated based on the monthly fuel use, the 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, 25 for CH₄, and 298 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 combined-cycle units (Emission IDs: CC1 and CC2) 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 combined-cycle units will use a water injection system to control NOx emissions while firing fuel oil. Refer to Section 3.0 “Review of Applicable Rules and Regulations” of this document for more detail on the CAM requirements for the combined-cycle units.

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 exist for NO₂, CO, PM_{2.5}, PM₁₀, SO₂, Ozone (O₃), and lead. PSD increments exist for SO₂, NO₂, PM_{2.5}, and PM₁₀.

The proposed Project at the Plant triggers PSD review for PM, PM₁₀, PM_{2.5}, NO_x, SO₂, VOC, CO, GHG in terms of CO_{2e}, and H₂SO₄ emissions. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO₂, CO, SO₂, PM_{2.5}, and PM₁₀, as applicable. 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 PM, PM₁₀, PM_{2.5}, NO_x, SO₂, VOC, CO, GHG in terms of CO_{2e}, and H₂SO₄ emissions greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment relevant to those pollutants.

VOC does not have established PSD modeling significance levels (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. Also, there are no NAAQS or PSD Increments for GHG or H₂SO₄. GHG has no direct modeling requirements. PM has no direct modeling requirements, but PM₁₀ and PM_{2.5} do have NAAQS/Increments and modeling requirements. H₂SO₄ is modeled as a Toxic Air Pollutant (TAP) where the maximum ground level concentration (MGLC) is compared to the Division's acceptable ambient concentrations (AAC).

Significance Analysis, Ambient Monitoring Requirements, and Source Inventories

Initially, a Significance Analysis is conducted to determine if PM, PM₁₀, PM_{2.5}, NO₂, SO₂, VOC, and 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.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. Generally, 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. For 1-hour NO₂, US EPA guidance suggests that an appropriate off-site inventory radius is generally limited to approximately 10-20 km; however, any large source just outside this radius would be considered.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (µg/m³)
PM _{2.5}	Annual	0.13
	24-Hour	1.2
PM ₁₀	Annual	1
	24-Hour	5
SO ₂	Annual	1
	24-Hour	5
	3-Hour	25
	1-Hour	7.8
NO ₂	Annual	1
	1-hour	7.5
CO	8-Hour	500
	1-Hour	2000

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 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.

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 ($\mu\text{g}/\text{m}^3$)	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	--
SO ₂	Annual	--	Revoked 08/23/2010 / 0.010
	24-Hour	Revoked 08/23/2010 / None	Revoked 08/23/2010 / None
	3-Hour	--	None / 0.5
	1-Hour	--	0.075 / None
NO ₂	Annual	100 / 100	0.053 / 0.053
	1-Hour	188 / 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, in the form of the applicable standard, would be added to appropriate background concentrations and assessed against the applicable NAAQS to demonstrate compliance.

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 NO₂, SO₂, PM₁₀ and PM_{2.5}; no increments have been established for CO. The PSD Increments are further broken into Class I, II, and III Increments. The Plant is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m ³)	Class II (ug/m ³)
PM _{2.5}	Annual	1	4
	24-Hour	2	9
PM ₁₀	Annual	4	17
	24-Hour	8	30
SO ₂	Annual	2	20
	24-Hour	5	91
	3-Hour	25	512
NO ₂	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, 1975. 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 April 30, 1998, and for NO₂ as May 5, 1988. The major and minor source baseline dates for PM_{2.5} are October 20, 2010 and October 20, 2011, respectively.

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 Volume II, Section 6 of the permit application.

Modeling Results

Table 6-4 show that the proposed Project will not cause ambient impacts of CO, SO₂, and 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 and PM_{2.5} for the 1-hour and 24-hour 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	1-hour	672.63	3,702.32	10.273**	7.5	Yes
	Annual	682.58	3,699.30	0.95295**	1	No
PM _{2.5}	24-hour	680.66	3,698.71	2.1297	1.2	Yes
	Annual	683.41	3,698.14	0.1268	0.2	No
PM ₁₀	24-hour	680.88	3,699.02	3.3822	5	No
	Annual	683.44	3,698.18	0.13521	1	No
SO ₂	1-hour	637.82	3,701.58	1.715530	7.8	No
	3-hour	682.88	3,699.61	1.1247	25	No
	24-hour	680.88	3,699.02	0.68628	5	No
	Annual	683.44	3,698.18	0.039670	1	No
CO	1-hour	673.82	3,701.58	520.63	2000	No
	8-hour	682.87	3,699.61	118.85***	500	No

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods. The applicant provided justification to support this decision.

** 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.

*** 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 below, maximum modeled impacts were below the corresponding Class I SILs for NO₂, PM_{2.5}, PM₁₀, and SO₂.

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

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)	SIL (ug/m ³)	Significant?
NO ₂	Annual	719.19	3,665.02	0.014310**	0.1	No
PM _{2.5}	24-hour	686.99	3,748.93	0.26282	0.27	No
	Annual	719.19	3,665.02	0.009295	0.03	No
PM ₁₀	24-hour	686.99	3,748.93	0.23703	0.3	No
	Annual	719.19	3,665.02	0.008850	0.2	No
SO ₂	3-hour	689.59	3,748.633	0.29820	1	No
	24-hour	686.99	3,748.93	0.048520	0.2	No
	Annual	719.19	3,665.02	0.002650	0.1	No

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods. The applicant provided justification to support this decision.

** 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.

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-hour NO₂ and 24-hour PM_{2.5}.

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

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

NAAQS Analysis

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

The results of the NAAQS analysis are shown in Table 6-6. When the total impact at all significant receptors within the SIA, in the form of the corresponding NAAQS standard(s), are below the corresponding NAAQS, compliance is demonstrated.

Table 6-6: NAAQS Analysis Results*

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)**	Background (ug/m ³)	Total Impact (ug/m ³)	NAAQS (ug/m ³)	Exceed NAAQS?
NO ₂	1-Hour	677.08	3,707.12	23.7083	30.3	54.008	188.0	No
PM _{2.5}	24-hour	683.33	3,697.22	3.8235	16.2	20.449	35	No

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods. The applicant provided justification to support this decision.

** Maximum modeled concentrations for all pollutants reflect the “ALL” source group.

As indicated in Table 6-6 above, all 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 6-7: Increment Analysis Results*

Pollutant	Averaging Period	UTM East (km)	UTM North (km)	Maximum Impact (ug/m ³)**	Increment (ug/m ³)	Exceed Increment?
PM _{2.5}	24-hour	680.803	3,698.86	2.9802	9	No

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods. The applicant provided justification to support this decision.

** Secondary PM_{2.5} concentrations are based on the hypothetical Tallapoosa, AL monitor and Project emissions. The applicant did not explicitly calculate the secondary impact from increment consumers for precursors in the offsite inventory. Instead, they demonstrated from an emissions trend analysis that NOx and SO2 emissions have decreased and therefore increment expansion has occurred since the original PM_{2.5} baseline dates were set.

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

Ambient Monitoring Requirements

Class I Area Analysis

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

The Class I area within approximately 200 kilometers of the Plant is the Cohutta Wilderness Area, located approximately 163 kilometers north-northeast of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of this Class I area.

Five Class I areas exist within a 300 km range from the Plant facility: Cohutta Wilderness(GA), Joyce Kilmer – Slickrock Wilderness Area (NC), Sipsey Wilderness (AL), Great Smoky Mountains National Park (TN), and Shining Rock Wilderness (NC). 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.

The Federal Land Managers’ *Air Quality Related Values Work Group Phase I Report (Revised 2010) (FLAG 2010)* guidance document contains a screening approach that is designed to screen

out projects from the need to conduct an AQRV analysis for nearby Class I areas. This screening approach is based on the Q/D ratio being less than 10, where ‘Q’ is the annual steady-state equivalent emission rate based on the sum of NO_x, SO₂, filterable PM₁₀, and H₂SO₄ emissions (expressed in tons per year, based on maximum 24-hour emissions), and ‘D’ is the distance (km) to the closest Class I area. The Project emissions for these pollutants was used to perform a Q/D screen. Table 6-8 provides the distance (D) from the proposed Project to each Class I area along with the Q/D ratio. Class I SIL modeling is described in previous sections. Based on the information in Table 6-8, the FLMs exempted the Project from the need to perform an AQRV analysis.

Table 6-8: Class I Q/D Calculations

Class I Area	Distance from Project (km)	Natural Gas Scenario Emissions (tpy)	Natural Gas Scenario Q/D	ULSD Scenario Emissions tpy	ULSD Scenario Q/D
Cohutta Wilderness	163	643.0	3.9	1,121.4	6.9
Joyce Kilmer – Slickrock Wilderness Area	236	643.0	2.7	1,121.4	4.8
Sipsey Wilderness	238	643.0	2.7	1,121.4	4.7
Great Smokey Mountains National Park	253	643.0	2.5	1,121.4	4.4
Shining Rock Wilderness	295	643.0	2.2	1,121.4	3.8

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 defines maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS have been adopted for SO₂, 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 7-1. The modeled concentrations are all well below each applicable secondary NAAQS; therefore, no significant impacts on local soils and vegetation are expected as a result of the Project.

Table 7-1: Comparison of Modeled Concentrations to Secondary NAAQS*

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m³)**	Secondary Impact (ug/m³)***	Total Concentration (ug/m³)	Secondary NAAQS (ug/m³)
NO ₂	Annual	0.014310****	N/A	0.014310****	100
PM _{2.5}	24-hour	0.236140	0.026683	0.262823	35
	Annual	0.008800	0.000495	0.009295	15
PM ₁₀	24-hour	0.237030	N/A	0.237030	150
	Annual	0.008850	N/A	0.008850	N/A
SO ₂	3-hour	0.298200	N/A	0.298200	N/A
	24-hour	0.048520	N/A	0.048520	N/A
	Annual	0.002650	N/A	0.002650	26.2

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods. The applicant provided justification to support this decision.

** Maximum modeled concentrations for all pollutants reflect the “ALL” source group.

*** Secondary PM_{2.5} impacts were estimated with the MERP approach using the NO_x and SO₂ emissions at the proposed facility.

****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.

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 the Project, 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 SO₂, 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.

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

As an additional refinement to the Level II analysis, the NOx emission rate was scaled by 75 percent following the Ambient Ration Method to account for the conversion of NOx to NO2 in the atmosphere, since the latter is the specific visibility-impairing species. All other parameters were input as Level I default options. A background visual range of 25 kilometers was used for the Plant.

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

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

Background	Theta	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	6	1.8	163	2.00	1.637	0.05	0.021
	140				2.00	1.389	0.05	-0.037

* VISCREEN was run using a level 2 analysis for an annualized scenario that accounts for 7,560 hours per year of natural gas firing and 1,200 hours per year of distillate oil firing. Maximum load emissions for each scenario were summed to compute the annual total filterable particulate matter, NOx, and primary sulfuric acid mist from the Project. The nearest visibility sensitive Class II area within the project’s largest SIA was Chattahoochee Bend State Park. The park’s visitor center opens at 9 AM and closes at 5 PM daily. Therefore, only the worst-case daytime stability classifications were considered for the Level 2 screening analysis (6 AM to 6 PM). The applicant characterized wind directions into two 23.5-degree sectors, from 228.5 to 252 degrees and 252 to 273.5 degrees from which the worst-case daytime stability class was selected. The DMU characterized wind directions into two 31.25-degree sectors, from 215 to 246.25 and 246.25 to 277.5 degrees from which the worst-case daytime stability class was selected. The applicant’s analysis of KATL surface data file from 2019-2023 determined the worst-case scenario to be stability class D with a wind speed of 4 m/s. The DMU’s analysis of the same surface data file determined the worst-case scenario to be stability class D with a wind speed of 3 m/s. Results from the DMU’s level 2 VISCREEN analysis are shown in Table 10. 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 surrounding area.

Moreover, an analysis of the Class II increment inventory at the Plant indicates that, since 1975, decreases in actual emissions of visibility-affecting pollutants from the facility far exceed any corresponding increases in potential emissions of these pollutants. Because the perception of

industrial plumes has not been an issue in the past, this indicates there is little reason to expect visible industrial plumes from this site will be a substantial future issue.

Georgia Toxic Air Pollutant Modeling Analysis

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

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed Project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the natural gas and distillate fuel 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 AACs were obtained following the procedures given in Georgia EPD's *Guideline*. 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 AERMOD. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling.

Georgia EPD's *Guideline* also contains the Minimum Emission Rates (MER). If a TAP's total emission rate is below the associated MER, no further analysis is required. The MER for each TAP is provided within Appendix A of the TAPs *Guideline*. For those TAPs with total emission rates above the MER, further analysis (modeling to compare against the AAC) is required.

Table 7-3: Facility-wide TAP Emissions and MER Comparison

Pollutants	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER?	AAC Analysis Required?
Arsenic	1.08E+02	5.67E-02	Y	Y
Beryllium	3.55E+00	9.73E-01	Y	Y
Cadmium	1.27E+02	1.35E+00	Y	Y
Chromium (III)	1.82E+02	5.84E+01	Y	Y
Chromium (VI)	2.11E+01	2.02E-02	Y	Y
Cobalt	7.68E+00	1.17E+01	N	N
Lead	1.57E+02	5.84E+00	Y	Y
Manganese	6.68E+03	1.22E+01	Y	Y
Mercury	3.06E+01	7.30E+01	N	N
Nickel	2.04E+02	3.86E+01	Y	Y
Selenium	2.10E+03	2.34E+01	Y	Y
Acetaldehyde	3.72E+03	1.11E+03	Y	Y
Acrolein	5.95E+02	4.87E+00	Y	Y
Ammonia	6.82E+05	2.43E+04	Y	Y
Benzene	1.43E+03	3.16E+01	Y	Y
1,3-Butadiene	1.69E+02	7.30E+00	Y	Y
1,1,1-Trichlorobenzene	1.40E+01	2.20E+05	N	N
Dichlorobenzene	1.78E-01	1.74E+04	N	N
Ethylbenzene	2.98E+03	2.43E+05	N	N
Formaldehyde	2.20E+04	2.67E+021	Y	Y
Hexane	2.67E+02	1.70E+05	N	N
Propylene Oxide	2.70E+03	6.57E+02	Y	Y
Sulfuric Acid	2.19E+05	1.17E+02	Y	Y
Toluene	1.21E+04	1.22E+06	N	N
Xylenes	6.03E+03	2.43E+04	N	N
Acenaphthene	2.93E-02	N/A	N	N
Acenaphthylene	5.99E-02	N/A	N	N
Anthracene	9.53E-03	N/A	N	N
Benz(a)anthracene	5.67E-03	N/A	N	N
Benzo(a)pyrene	1.89E-03	N/A	N	N
Benzo(b)fluoranthene	6.91E-03	N/A	N	N
Benzo(g,h,i)perylene	3.96E-03	N/A	N	N
Benzo(k)fluoranthene	1.71E-03	N/A	N	N
Chrysene	9.64E-03	N/A	N	N
Dibenzo(a,h)anthracene	2.82E-03	N/A	N	N
Dimethylbenz(a)Anthracene, 7,12-	2.37E-03	N/A	N	N
Fluoranthene	3.21E-02	N/A	N	N
Fluorene	1.06E-01	N/A	N	N
Indeno(1,2,3-cd)pyrene	3.09E-03	N/A	N	N
Methylnaphthalene, 2-	3.55E-03	N/A	N	N
Methylcholanthrene, 3-	2.66E-04	N/A	N	N
Naphthalene	4.00E+02	7.30E+02	N	N
Phenanathrene	2.73E-01	N/A	N	N
Pyrene	2.75E-02	N/A	N	N
Total POM	4.01E+02	N/A	N	N

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 7-4 summarizes the AAC levels and MGLCs of the seventeen TAPs. As shown in Table 7-4, the modeled MGLCs for all seventeen TAPs are below their respective AAC levels.

Table 7-4. Modeled MGLCs and the Respective AACs.

TAP	Averaging Period	AAC (µg/m ³)	Max Modeled Conc. (µg/m ³)
Acetaldehyde	15-min	4,500	0.343251
	Annual	4.55	0.000987
Acrolein	15-min	23	0.042865
	Annual	0.35	0.000158
Ammonia	15-min	2,400	8.633236
	Annual	100	0.180289
Arsenic	15-min	0.2	0.010658
	Annual	0.000233	0.000025
Benzene	15-min	1,600	0.789901
	Annual	0.13	0.000622
Beryllium	15-min	0.5	0.000300
	Annual	0.004	0.000001
1,3-Butadiene	15-min	1,100	0.010489
	Annual	0.03	0.000039
Cadmium	15-min	30	0.004646
	Annual	0.00556	0.000033
Chromium (III)	24-hour	1.2	0.002059
Chromium (VI)	15-min	10	0.001918
	Annual	0.0000555	0.000005
Formaldehyde	15-min	245	0.541113
	Annual	0.0909	0.005875
Lead	24-hour	0.12	0.003194
Manganese	15-min	500	0.766752
	Annual	0.05	0.001505
Nickel	24-hour	0.794	0.001053
Propylene Oxide	Annual	2.7	0.000712
Selenium	24-hour	0.48	0.056362
Sulfuric Acid	15-min	300	2.778112
	24-hour	2.4	1.000120

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-149-0014-P-01-0.

Section 1.0: Facility Description

“The Plant” applied for a greenfield permit to construct and operate two (2) advanced class, dual-fuel combined-cycle (CC) electrical generating units at Plant Wansley located in Heard County, Georgia. The proposed Project will construct the proposed CC units and will include installation of new associated equipment, such as emergency generators, an emergency fire water pump engine, cooling towers, distillate oil storage tanks, and two fuel gas heaters.

Section 2.0: Requirements Pertaining to the Entire Facility

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

Section 3.0: Requirements for Emission Units

Permit Condition 3.2.1 states the fuel consumption limit for the distillate oil fired in each combustion turbine. The fuel oil limit was used in modeling as a part of the scenario since the turbine’s primary fuel is natural gas, they used the value of the fuel oil limit as a dispersion modeling worse-case scenario.

Permit Conditions 3.3.1 through 3.3.4 contain the 40 CFR 60 Subpart KKKKa requirements for the combustion turbines.

Permit Condition 3.3.5 contains the 40 CFR 60 Subpart TTTT or TTTTa requirements for the combustion turbines.

Permit Conditions 3.3.6 through 3.3.9 contain the 40 CFR 52.21 (PSD) and 40 CFR 60 Subpart KKKKa emission limits and requirements for the combustion turbines.

Permit Conditions 3.3.10 and 3.3.13 contain the 40 CFR 63 Subpart YYYY requirements for the combustion turbines.

Permit Condition 3.3.14 states the general applicability of the Boiler MACT for the Water Bath Heaters (Emission IDs: WBH1 and WBH2).

Permit Condition 3.3.15 has the Boiler MACT work practice standards for the Water Bath Heaters WBH1 and WBH2.

Permit Condition 3.3.16 requires the water bath heaters to only fire pipeline quality natural gas.

Permit Condition 3.3.17 contains the PSD emission limits for the water bath heaters.

Permit Condition 3.3.18 requires the use of a submerged fill pipe for the fuel oil storage tank.

Permit Condition 3.3.19 requires the installation of high-efficiency drift eliminators on the cooling towers.

Permit Condition 3.3.20 addresses the applicability of 40 CFR Part 63 NESHAP Subpart ZZZZ for the emergency engines (Emission IDs: EG1, EG2, and EG3) and emergency fire pump engine (Emission ID: FP1).

Permit Conditions 3.2.21 and 3.2.22 addresses the applicability of 40 CFR Part 60 NSPS Subpart IIII for the emergency engines (Emission IDs: EG1, EG2, and EG3) and emergency fire pump engine (Emission ID: FP1).

Permit Condition 3.2.23 limits total annual operating hours for the emergency fire pump engine to not exceed 500 hours per twelve consecutive months.

Permit Condition 3.2.24 lists the emission standards of 40 CFR 60 Subpart IIII, applicable to the emergency generators.

Permit Condition 3.2.25 limits the total annual hours of operation of each emergency generator to not exceed 200 hours per generator during any twelve consecutive months according to Georgia Rule (mmm).

Permit Condition 3.2.26 specifies that the emergency engines and fire water pump engine are only allowed to burn diesel fuel that has a maximum sulfur content of 15 ppm (0.0015% by weight) and either a minimum cetane index of 40 or maximum aromatic content of 35 volume percent.

Permit Condition 3.2.27 specifies purchased engines for the emergency generators and fire water pump engine should be certified to meet the applicable requirements in 40 CFR Subpart IIII.

Permit Condition 3.3.28 requires emergency generators and emergency fire pump are operated and maintained according to manufacturer's written instructions or procedures.

Permit Conditions 3.4.1 and 3.4.2 contain the Georgia Rule (d) and Georgia State Rule (nnn) requirements for the combustion turbines and duct burner.

Permit Conditions 3.4.3 and 3.4.4 contains Georgia Rule (d) requirements for the water bath heaters.

Permit Condition 3.4.5 contains Georgia Rule (b) requirements for the emergency generators and emergency fire pump engine.

Section 4.0: Requirements for Testing

Permit Condition 4.1.1 includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division.

Permit Condition 4.1.2 states a written notification of any performance test(s) is required 30 days (or sixty (60) days for tests required by 40 CFR 63) prior to the date of the test(s), as well as a test plan to be submitted with the test notification.

Permit Condition 4.1.3 states General Test Method Requirements.

Permit Condition 4.1.4 requires performance test results be submitted via CEDRI.

Permit Condition 4.1.5 requires all monitoring systems and/or monitoring devices required by the Division to be installed, calibrated and operational prior to conducting any performance test(s).

Permit Conditions 4.2.1 through 4.2.5 contain the special testing requirements for the combustion turbines and duct burners.

Section 5.0: Requirements for Monitoring

Permit Condition 5.2.1 includes CEMS monitoring requirements for the combustion turbines and duct burner.

Permit Condition 5.2.2 requires the facility to install a continuous monitoring system to record the quantity of natural gas, in cubic feet, burned in each combustion turbine and duct burner, quantity of distillate oil, in gallons, burned in each combustion turbine, and inlet temperature to the oxidation catalyst for each combustion turbine.

Permit Condition 5.2.3 requires the facility to assess the quality and accuracy of the data acquired by the NO_x CEMS.

Permit Conditions 5.2.4 through 5.2.10 states the quality assessment requirements of the NO_x CEMS and the CO CEMS for the combustion turbines.

Permit Conditions 5.2.11 and 5.2.12 require fuel supplier certifications for the pipeline quality natural gas and fuel oil fired in the combustion turbines.

Permit Condition 5.2.13 contains CMS requirements.

Permit Condition 5.2.14 includes the tune-up requirements for water bath heaters WHB1 and WB2.

Permit Condition 5.2.15 contains additional tune up monitoring requirements for the water bath heaters.

Permit Condition 5.2.16 requires fuel quantity usage monitors on the water bath heaters.

Permit Condition 5.2.17 requires the installation of a non-resettable hour meter to monitor the hours of operation of the emergency generators and emergency fire pump engine.

Section 6.0: Other Recordkeeping and Reporting Requirements

Permit Condition 6.1.1 to 6.1.8 explains general recordkeeping and reporting requirements.

Permit Condition 6.2.1 through 6.2.3 were added to require recordkeeping of fuel usage requirements in the combustion turbines and duct burners.

Permit Conditions 6.2.4 through 6.2.7 require recordkeeping of verification of compliance with NOx emission limits for the combustion turbines and duct burners.

Permit Conditions 6.2.8 through 6.2.10 were added to require recordkeeping of verification of compliance with CO emission limits for the combustion turbines and duct burners.

Permit Conditions 6.2.11 through 6.2.13 to require recordkeeping of verification of compliance with greenhouse gas emission limits for the combustion turbines and duct burners.

Permit Conditions 6.2.14 through 6.2.16 require recordkeeping of verification of compliance with operational limits for the combustion turbines.

Permit Conditions 6.2.17 through 6.2.19 includes recordkeeping and reporting requirements for the water bath heaters.

Permit Condition 6.2.20 state the quarterly reporting requirements for the combustion turbines and duct burners.

Permit Condition 6.2.21 and 6.2.22 state the Georgia Rule (nnn) recordkeeping and reporting requirements for the combustion turbines and duct burners.

Permit Condition 6.2.23 through 6.2.25 state the 40 CFR 60 Subpart TTTT or TTTTa recordkeeping and reporting requirements for the combustion turbines and duct burners.

Permit Condition 6.2.26 through 6.2.30 state the 40 CFR 63 Subpart YYYY recordkeeping and reporting requirements for the combustion turbines.

Permit Condition 6.2.31 states the construction and startup notification requirements.

Permit Conditions 6.2.32 through 6.2.34 state the special testing and turbine tuning requirements.

Permit Conditions 6.2.35 and 6.2.36 specify record requirements for the emergency generators and the emergency fire pump engine.

Section 7.0: Other Specific Requirements

This section includes general PSD construction timeframe conditions, Georgia general requirements for reporting of initial construction, and Title V application submittal requirements.

Section 8.0: General Provisions

The general provisions found in Georgia SIP permits are included here.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Georgia Power Company (GPC) Wansley Combined-Cycle Facility
Carrollton (Heard County), Georgia

APPENDIX B

Georgia Power Company (GPC) Wansley Combined-Cycle Facility PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 29734, dated June 9, 2025

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review