Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

June 2026

Facility Name: McIntosh Combined Cycle Facility
City: Rincon
County: Effingham
AIRS Number: 04-13-103-00014
Application Number: 959863
Date Application Received: November 4, 2025

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by McIntosh Combined-Cycle Facility (Plant McIntosh) referred to as "The Plant" for a permit to construct and operate up to two (2) new combined-cycle (CC) units at Plant McIntosh located in Effingham County, Georgia.

The proposed project will include the construction of up to two (2) combined-cycle (CC) electric generating units, arranged in a 1-on-1 configuration, each of which includes an advanced class dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator. Each 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 nitrogen oxide (NO_X) formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_X formation. Each HRSG will be equipped with a selective catalytic reduction (SCR) and an oxidation catalyst system to reduce NO_X, carbon monoxide (CO), and volatile organic compound (VOC) emissions.

The proposed project will result in an increase in emissions from the Plant. The sources of these increases in emissions include the two (2) advanced class dual-fuel CC units and the following associated equipment: two (2) multi-cell mechanical draft cooling towers, two (2) fuel gas heaters, one (1) fixed roof distillate oil storage tank, two (2) 2,000 kW emergency generators, one (1) 500 kW emergency generator, and one (1) 350 bhp fire water pump engine.

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

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

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

It is the preliminary determination of the EPD that the proposed project provides for the application of Best Available Control Technology (BACT) for the control of PM (TSP), PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, CO, GHG in terms of carbon CO_2e, and H_2SO_4 emissions, 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 Plant or in Class I areas located within 300 km of the Plant. It has further

been determined that the proposed project will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to McIntosh Combined-Cycle Facility for the modifications necessary to construct and operate up to two (2) combined-cycle (CC) electric generating units at Plant McIntosh. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On November 4, 2025, McIntosh Combined-Cycle Facility (hereafter "Plant McIntosh") submitted an application for an air quality permit to construct and operate up to two (2) new CC units, which will include the installation of the following associated equipment: two multi-cell mechanical draft cooling towers, two fuel gas heaters, one fixed roof distillate oil storage tank, three emergency generators, and one fire water pump engine. The Plant is located at 900 Old Augusta Road Central in Rincon, Effingham County.

Table 1-1: Title V Major Source Status

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

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

Table 1-2: List of Current Permits, Amendments, 502(b)(10) Changes, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-103-0014-V-06-0	November 10, 2020	Title V Renewal
4911-103-0014-V-06-1	December 8, 2023	Update of 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT) conditions.
4911-103-0014-V-06-2	December 8, 2023	Renewal of Acid Rain Permit

<u>PSD Applicability Analysis</u>

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

52.21(b)(48)(iii)) equals or exceeds the significant emission rate for that pollutant (as defined in 40 CFR Part 52.21(b)(23)).

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

Emissions of regulated NSR pollutants are based, in part, by assuming no capacity factor limit and: (1) a maximum of 29,900,000 gallons per year of distillate oil fired in each CC; (2) a sulfur content limit of natural gas of 0.5 grains per 100 standard cubic feet; and (3) a sulfur content limit of fuel oil of 15 ppm. Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the Plant are listed in Table 1-3 below.

Emissions of regulated NSR pollutants are based, in part on the following operating parameters for the auxiliary equipment as follows; (1) 8,760 hrs/yr of natural gas combustion per heater; (2) 500 hrs/yr of ultra-low sulfur fuel oil combustion for the emergency generators; (3) 500 hrs/yr of ultra-low sulfur fuel oil combustion for the emergency fire-water pumps; and (4) 29,900,000 gal/yr each of annual throughput for the Turbine Fuel Diesel Storage Tanks.

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the Plant are listed in Table 1-3 below. As shown in Table 1-3, the Project triggers PSD review for several criteria pollutants. Total HAP potential to emit from the Project will exceed 25 tons/year, and individual HAP potential to emit will exceed 10 tons per year (see Appendix C of the application for details).

Table 1-3: Emissions Increases from the Project

Pollutant	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
[1]PM	130.1	25	Yes
[1]PM_{10}	235.9	15	Yes
[1]$PM_{2.5}$	233.6	10	Yes
VOC	327.2	40	Yes
NO_X	429.7	40	Yes
CO	532.6	100	Yes
SO_2	72.3	40	Yes
Pb	0.1	0.6	No
SAM	110.5	7	Yes
[2]CO_2e	5,571,760	75,000	Yes

1. PM is filterable PM emissions only. PM_{10} and $PM_{2.5}$ include both filterable and condensable PM emissions.
2. CO_2e is the number of tons of CO_2 emissions with the same global warming potential as one ton of another greenhouse gas. CO2e includes CO_2 emissions, CH_4 emissions as CO_2e, and N_2O emissions as CO_2e.

The emissions calculations for Table 1-3 can be found in detail in the Plant's PSD application (see Appendix C of Application No. 959863). These calculations have been reviewed and approved by the Division.

Based on the information presented in Table 1-3 above, Plant McIntosh's proposed modification, as specified per Georgia Air Quality Application No. 959863, is classified as a major modification under PSD because the potential emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, CO, GHG in terms of carbon CO_2e, and H_2SO_4 exceed PSD thresholds. The net emissions increase for the project is equivalent to the potential emissions from the new emission units comprising the project because the baseline for those units is equal to zero and there are no contemporaneous projects to be considered in the net emissions increase analysis.

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

2.0 PROCESS DESCRIPTION

According to Application No. 959863, the Plant has proposed to construct up to two combined-cycle electric generating units (Emission Unit IDs CT12/DB12 and CT13/DB13) 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 capable of firing either natural gas or ultra-low sulfur distillate oil,
  - Heat recovery steam generator (HRSG) with natural gas-fired duct burner, and
  - Steam turbine (ST) generator.

Additional equipment associated with the project includes:

- Two (2) multicell 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)
- One (1) 102' diameter distillate oil storage tanks with submerged filling with a working capacity of 2.445 million gallons (each)
- Two (2) Tier 2 2,000 kW emergency generators
- One (1) Tier 2 500 kW emergency generators
- One (1) Tier 3 350 hp fire water pump engine

Combustion Turbines

The CT is the main component of each proposed CC unit and consists of three major sections: a high-efficiency compressor, a combustor, and a high-efficiency turbine to generate power with the associated generator.

In the compressor section, ambient air is drawn through a filter. Once filtered, evaporative cooling is used to cool the air and increase power output when ambient temperatures are sufficiently high. The air is then compressed and directed to the combustor section.

In the combustor, a mixture of fuel and air is introduced and combusted. The CT will be capable of firing either pipeline quality natural gas or distillate oil. When firing natural gas, dry low-NO_X (DLN) combustors will reduce NO_X formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_X formation. Exhaust gases, at high temperature and pressure, are then directed to the turbine section to generate power.

In the turbine, the exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

Heat Recovery Steam Generators

The exhaust gases exiting the CT will be ducted to a horizontal, natural circulation, three-pressure level HRSG where high, intermediate, and low-pressure steam will be produced and used in the

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

Cooling Towers

Each proposed CC unit will be served by a multi-cell wet mechanical induced draft cooling tower that will provide cooling water to be used in the condensers for the ST generator exhaust as well as various process heat exchangers. The design circulating water flow rate for each cooling tower is 150,000 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 NO_X emissions.

Distillate Oil Storage Tank

The proposed CC units will be served by one aluminum vertical fixed-roof storage tank for onsite storage of distillate oil to provide reliability and resiliency benefits to the electric system. The tank will be approximately 102 feet in diameter and have a working capacity of 2.445 million gallons. Emissions of VOC from the tanks will be minimized by equipping the tank with submerged filling to reduce working losses. A light-colored or reflective paint for the tank shell and roof will be used to minimize evaporative losses.

Emergency Generators and Fire Water Pump Engine

The Project will include up to two (2) 2,000 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 emissions standards, and be operated no more 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. The fire water pump engine will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 500 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. All emergency generators and the fire water pump engine will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

The Plant McIntosh 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 Plant 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 Plant can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1.02(2)(b) – Visible Emissions
Rule (b) limits the visible emissions from any emissions source to 40% opacity, unless they are subject to some other visible emissions limitation under GRAQC 391-3-1-.02. Visible emissions testing may be required at the discretion of the Director.

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

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

Georgia Rule 391-3-1.02(2)(d) – Fuel-Burning Equipment
Rule (d) limits visible emissions, PM emissions, and NO_X emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. As defined in 391-3-1-.01(cc), fuel burning equipment is:

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

The emergency generators and fire water pump engine are not subject to Rule (d) because these engines will not produce thermal energy to furnish process heat indirectly (i.e., are not fuel burning equipment). However, thermal energy from the proposed CC units and 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 the more stringent BACT limits.

Georgia Rule 391-3-1.02(2)(g) – Sulfur Dioxide
Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to all "fuel-burning sources" and not just "fuel-burning equipment," Rule (g) applies to the CC units, emergency generators, firewater pump engine, and the fuel gas heaters.

For fuel-burning sources below 100 MMBtu/hr, such as the proposed fuel gas heaters, emergency generators, and fire water pump engine, the fuel sulfur content is limited to 2.5% sulfur by weight. For fuel-burning sources above 100 MMBtu/hr, such as the combustion turbines and duct burners in the proposed CC units, the fuel sulfur content is limited to 3.0% sulfur by weight. Sulfur dioxide emissions from each combustion turbine shall not exceed 0.8 lb/MMBtu of heat input derived from distillate (liquid) oil in accordance with Rule 391-3-1-.02(2)(g)1(i).

The Rule (g) fuel sulfur content limits and SO_2 emission limitation will be subsumed by more stringent BACT limits in accordance with NSPS Subpart KKKKa for the CC units and NSPS Subpart IIII (0.0015% sulfur by weight) for the emergency generators and fire water pump engine.

Georgia Rule 391-3-1.02(2)(n) – Fugitive Dust
The fugitive dust rule applies to any operation, process, handling, transportation, or storage Plant which has the potential to produce airborne dust. The Plant will employ appropriate control methods and take precautions to limit fugitive dust emissions from the project so as not to exceed 20% opacity.

Georgia Rule 391-3-1.02(2)(bb) – Petroleum Liquid Storage
Rule (bb) establishes requirements for storage tanks with a capacity greater than 40,000 gallons storing a petroleum liquid with a true vapor pressure greater than 1.52 pounds per square inch absolute (psia). Since distillate oil has a maximum true vapor pressure less than 1.52 psia, the proposed distillate oil storage tanks are not subject to the requirements of Rule (bb).

Georgia Rule 391-3-1-.02(2)(nn) – VOC Emissions from External Floating Roof Tanks
Rule (nn) establishes requirements for external floating roof tanks storing petroleum liquids with a capacity greater than 40,000 gallons. As the proposed fuel oil storage tank is a fixed roof tank and not an external floating roof tank, Rule (nn) will not apply.

Georgia Rule 391-3-1-.02(2)(uu) – Visibility Protection
This rule requires the Division 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. 959863.

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

These regulations incorporate the Cross State Air Pollution Rule (CSAPR) requirements into the Georgia Rules for Air Quality Control. The regulations provide allocations for Georgia for 2017 and thereafter. The proposed CC units are subject to this rule. The Plant will demonstrate compliance in accordance with 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 Rule 391-3-1-.03(1) – Construction (SIP) Permitting

The proposed project will require physical construction activities to complete the proposed modifications. Potential emissions associated with the proposed project to install the CC units, cooling towers, fuel gas heaters, emergency generators, and fire water pump engine are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i). Furthermore, as discussed in Section 1.2 of the application, PSD permitting is required for multiple pollutants.

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

The Plant is a Title V source and currently operates under Permit No. 4911-103-0014-V-06-0 and Permit Amendment No. 4911-103-0014-V-06-1. It will remain a major source following completion of the project. The application requested a significant modification with construction (PSD) to the Plant's Title V permit and included the SIP Permit application submitted for the Project in Appendix A of the application.

Ga. Comp. R & Regs. 391-3-1-.13 – Acid Rain

These regulations set a cap on SO_2 emissions from power plants by allocating a fixed number of allowances to units subject to the program. At the end of each year, a unit must surrender allowances in an amount equal to the number of tons of SO_2 emitted. Unused allowances may be sold to offset the cost of compliance or saved, i.e., banked, for future use. Initial allowance allocations were received in 1995 when Phase I of the program began. When Phase II began in 2000, the number of allowances available was reduced to limit SO_2 emissions to 50% below 1980 levels by 2010. The regulations also set emission rate limitations on NO_X emissions from coal units, which can be met by individual units or by a group of units under an averaging plan.

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.

The Acid Rain permit application is included in Appendix A of the application. The Plant will continue to operate in compliance with applicable provisions of the Title IV Acid Rain rules as adopted by reference in Ga. Comp. R & Regs. 391-3-1-.13. Additionally, 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 Rule - PSD

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

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

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

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

Definition of BACT

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

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

Step 1: Identification of all control technologies;

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

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

New Source Performance Standards

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

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

40 CFR Part 60, Subpart 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 Subpart KKKKa.

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 Plant subject to this standard and the duct burners are regulated under Subpart KKKKa.

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

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 Subpart KKKKa and (2) the fuel gas heaters each have a heat input capacity less than 100 MMBtu/hr.

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

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 Subpart KKKKa and (2) the fuel gas heaters have a heat input capacity less than 10 MMBtu/hr.

<u>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</u>

NSPS Subpart Kc applies to storage vessels with a capacity greater than 20,000 gallons that are used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after October 4, 2023. The proposed Project will have a storage tank for the distillate oil that will be used for the proposed CC units, emergency generators, and 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. The maximum true vapor pressure of distillate oil will be much less than 0.25 psia (~0.01 psia). Therefore, the proposed distillate oil storage tank associated with the Project will not be subject to the requirements of this subpart.

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

NSPS Subpart III is applicable to manufacturers, 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 manufacturer 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 Part 1039. The Plant will comply with all applicable Subpart IIII monitoring, recordkeeping, and reporting requirements. Because the engines will be designated and operated as emergency engines, they will only be operated in emergency circumstances and for a maximum of 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations.

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

NSPS Subpart KKKKa establishes NO_X and SO_2 emission standards for stationary combustion turbines that commence construction, modification, or reconstruction after December 13, 2024, and have a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value. The proposed CC units will be subject to this rule.

Emission Limits for NO_X

Under Subpart KKKKa, the proposed CC units are subject to a 4-operating-hour rolling NO_X emission standard, where the applicable standard for each operating hour is 5 ppm, corrected to 15% O_2, when firing natural gas, 42 ppm, corrected to 15% O_2, when firing distillate oil, or 96 ppm, corrected to 15% O_2, when firing either fuel and operating at less than 70% load or during periods of turbine tuning. The regulations also provide for optional output-based standards based on a 30-day rolling average.

As discussed in the BACT analysis in Section 4.0, the proposed CC units will reduce NO_X emissions using DLN, water injection, and SCR to comply with Subpart KKKKa. Compliance with the Subpart KKKKa emissions standards will be verified based on CEMS data.

Emission Limits for SO_2

The proposed CC units will be subject to an SO_2 emission standard of 0.9 lb/MWh, or a fuel sulfur limit equivalent to 0.06 lb SO_2/MMBtu heat input. The Plant will comply with the input-based SO_2 emission standard by utilizing natural gas or distillate oil as fuel, which both have sulfur contents lower than necessary to meet the 0.06 lb SO_2/MMBtu limit.

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

NSPS Subpart TTTTa establishes GHG emission standards for stationary combustion turbines that commence construction or reconstruction after May 23, 2023, have a base load rating greater than 250 MMBtu/hr, and serve a generator capable of selling more than 25 MW of electricity to a utility power distribution system. Under this subpart, one of three CO_2 standards may apply depending on capacity factors (net generation) during both the previous 12 operating months and 36 calendar months (3-year rolling). When the capacity factors are more than 20% but less than or equal to 40%, a sliding-scale emission standard of 1,170 to 1,560 lb/MWh-gross applies. If the capacity factors are more than 40%, a sliding-scale emission standard of 800 to 1,250 lb/MWh-gross applies before 2032, after which the standard is lowered to as low as 100 lb/MWh-gross. However, when the capacity factors are 20% or less all that is required is combustion of low-emitting fuels such as natural gas and distillate oil.

The Division notes that EPA has proposed to repeal portions of this rule that would impose a more stringent standard for units with capacity factors higher than 40% beginning in 2032.

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

The Plant is currently classified as an existing major source of HAPs (having potential emissions greater than 25 tpy of total HAP and/or 10 tpy of individual HAP), and the emission units constructed as part of the Project will be subject to the provisions of several subparts of 40 CFR Part 63. The Division has incorporated these rules by reference under Ga. Comp. R & Regs. 391-3-1-.02(9). An analysis of the applicability of each of the potentially applicable subparts is provided below. In addition to the General Provisions provided in 40 CFR Part 63, Subpart A, the NESHAP subparts potentially applicable to the Project include:

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

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

<u>40 CFR 63 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</u>
This subpart applies to stationary combustion turbines located at major sources of HAP. The proposed CC units are subject to a formaldehyde emission limit of 91 ppbvd, corrected to 15% O_2, and other associated requirements, including an initial notification and testing. The Plant will comply with the requirements of this subpart by equipping the proposed CC units with oxidation catalysts.

<u>40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</u>
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 63.6590(c)(6), the fire water pump engine will comply with the requirements of this subpart by complying with NSPS Subpart IIII. No initial notification is required for the fire water pump engine.

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 (Boiler MACT) establishes emission limitations and work practice standards for industrial, commercial, and institutional boilers and process heaters constructed or reconstructed after June 4, 2010 and located at major sources of HAP.

As defined in 40 CFR 63.7575, a "process heater" is:

> *"…an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials."*

The proposed fuel gas heaters 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, or the operating limits in Table 4. However, 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 projects.

State and Federal – Startup and Shutdown and Excess Emissions

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

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

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

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

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

Federal Rule – 40 CFR 68 – Risk Management Plan

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

The three elements that must be incorporated into a source's RMP include:

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

The Project will store and utilize anhydrous ammonia in the SCR systems to control NO_X emissions from the proposed CC units. Total anhydrous ammonia stored onsite is greater than the threshold quantity; RMP requirements will thus apply to these systems.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that trigger PSD review for the following pollutants: PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, SO_2, H_2SO_4, and GHG in terms of CO_2e.

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – Background

The proposed combined-cycle electric generating Units 12 and 13 (Source Codes CT12/DB12 and CT13/DB13), arranged in a 1-on-1 configuration, will each consist of an advanced-class dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator.

Combustion Turbines (CT12 and CT13)
The CT is the main component of each proposed CC unit and consists of three major sections: a high-efficiency compressor, a combustor, and a high-efficiency turbine to generate power with the associated generator. In the compressor section, ambient air is drawn through a filter. Once filtered, evaporative cooling is used to cool the air and increase power output when ambient temperatures are sufficiently high. The air is then compressed and directed to the combustor section.

In the combustor, a mixture of fuel and air is introduced and combusted. The CT will be capable of firing either pipeline quality natural gas or distillate oil. When firing natural gas, dry low-NO_X (DLN) combustors will reduce NO_X formation. Water injection will be used when firing distillate oil to minimize peak flame temperature and reduce NO_X formation. Exhaust gases, at high temperature and pressure, are then directed to the turbine section to generate power.

In the turbine, the exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

Heat Recovery Steam Generators (HRSG)
The exhaust gases exiting the CT will be ducted to a horizontal, natural circulation, three-pressure level HRSG where high, intermediate, and low-pressure steam will be produced and used in the ST to generate additional electricity. Each HRSG will be equipped with natural gas-fired duct burners (DB12 and DB13) which can be used to provide additional steam generating capacity only when the CT is firing natural gas. SCR and oxidation catalyst systems will be installed in each HRSG to reduce emissions of NO_X, CO, and VOC.

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

Cooling Towers

Each proposed CC unit will be served by a multi-cell wet mechanical induced draft cooling tower that will provide cooling water to be used in the condensers for the ST generator exhaust as well as various process heat exchangers. The design circulating water flow rate for each cooling tower is 150,000 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 NO_X emissions.

Distillate Oil Storage Tank

The proposed CC units will be served by one aluminum vertical fixed-roof storage tank for onsite storage of distillate oil to provide reliability and resiliency benefits to the electric system. The tank will be approximately 102 feet in diameter and have a working capacity of 2.445 million gallons. Emissions of VOC from the tank will be minimized by equipping the tank with submerged filling to reduce working losses. A light-colored or reflective paint for the tank shell and roof will be used to minimize evaporative losses.

Emergency Generators and Fire Water Pump Engine

The Project will include up to two (2) 2,000 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 emissions standards, and be operated no more 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. The fire water pump engine will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 500 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. All emergency generators and the fire water pump engine will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – BACT Review

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – 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.

NOx Formation – Combustion Turbines

There are five (5) primary pathways of NO_X production from turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. The three most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X. For natural gas-fired units, most NO_X is derived from thermal NO_X. Distillate oils also have low levels of fuel-bound nitrogen (N_2) that contribute to NO_X formation.

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

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

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

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

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

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

EPA's control technology database was searched, relevant existing and proposed federal and state emissions standards were considered, recently issued new source review permits and associated applications were reviewed, if available, for similar sources, and interviews with original equipment manufacturer (OEMs) and owner/operators of similar large, advanced class dual-fuel CC units to identify potentially available control options for NO_X emissions from the proposed CC units were conducted.

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

- A search of the RBLC was conducted to identify NO_X BACT determinations for large natural gas-fired and distillate oil-fired CC units (larger than 25 MW) permitted in the past ten years (i.e., since 2014).

- Permits and associated applications, if available, for large (>25 MW) CC units not found in the RBLC but:

  - Listed as commencing commercial operation within the last five years (i.e., since 2019) in EPA's National Electric Energy Data System (NEEDS) database (11 additional facilities);[1]

  - Listed as planned and under construction in EIA's Annual Electric Power Industry Report, Form EIA-860 (six additional facilities);[2]

- New and proposed federal and state emissions standards; and

- Interviews with original equipment manufacturers (OEMs) and owner/operators of similar large, advanced class CC units.

Each of these control technologies are addressed as follows:

Water or Steam Injection
Water or steam injection was determined by EPA to be the best technology to reduce NO_X emissions from stationary CT units when the national emissions standards for this source category were first established in 1977. 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 all reduced.

Dry Low NO_X (DLN) 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.

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

[2] Available at https://www.eia.gov/electricity/data/eia860m/. 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 Center, 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.

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

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}O_2 = 2N_2 + CO_2 + 2\ H_2O \qquad (1)$$

$$4\ NH_3 + 6NO = 5N_2 + 6\ H_2O \qquad (2)$$

Typical removal efficiencies for SNCR range from 30 percent to 50 percent and higher when coupled with combustion controls. 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. Operation at temperatures below this range results in ammonia slip. Operation at temperatures above this range results in oxidation of ammonia, forming additional NO_X emissions. Therefore, the SNCR injection system must be located such that operating temperatures are within the identified range.

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

Selective Catalytic Reduction (SCR)
SCR is a post-combustion control which involves the gas phase reaction of NO_X 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 NO_X to nitrogen and water vapor by the following chemical reactions:

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

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

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

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

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

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

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

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

Use of Water/Steam Injection and DLN Combustors
Use of DLN combustors and water injection is inherent to the Project and technically feasible.

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

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

Selective Catalytic Reduction
The use of SCRs is technically feasible and is included in the Project.

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

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

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

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

Selection of Emission Limits for NO_X BACT – CC Units (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 while firing natural gas, 42 ppmvd while firing distillate oil, and 96 ppmvd when operating at part-load while firing either fuel or during periods of turbine tuning.[3]

Based on the Plant review, NOx BACT for the proposed CC units should be based on the use of DLN combustors, water injection, and SCR. Therefore, the Plant proposes the following BACT limits:

- 2.0 ppmvd NO_X or less (corrected to 15% O_2) 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 (corrected to 15% O_2) when firing distillate oil based on a 4-hour rolling average, excluding periods of startup, shutdown, or fuel switching.

- 205.8 tons NO_X or less (per combustion turbine) during any 12-consecutive month period, including periods of startup, shutdown, and fuel switching.

For natural gas, the Plant is proposing the level of control equivalent to the most stringent emission limit achieved in practice. This level of control is the same as Plant Barry Unit 8 (AL-0328) and Jackson Energy Center (JEC) Units 1 and 2 (IL-0130), which are the most similar CC units in commercial operation in the U.S., except that those units are gas-fired only and are not capable of firing distillate oil as a backup fuel.[4]

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.[5] Sewaren Unit 7 is a second-generation General Electric (GE) H-class unit (GE 7HA.02) and has approximately 30% lower NO_X emissions in the CT exhaust (and

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

[4] 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)).

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

inlet to the SCR) compared to the proposed CC units, due to their lower firing temperature. To account for this significant difference between Sewaren Unit 7 and the Project, the Plant is proposing 5 ppmvd as NO_X BACT when firing distillate oil.

Compliance with the NO_X BACT emission limits will be determined by CEMS. Similar to other CC units permitted by EPD, 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 NO_X BACT emission limits above, the following definitions apply:

> *Startup* means the period of time from when the combustion turbine is first fired to when the load has been achieved at which it has been demonstrated by a CEMS or during compliance testing that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 288 minutes for a cold startup, 212 minutes for a warm startup, and 131 minutes for a hot startup while firing natural gas and 315 minutes for a cold startup, 232 minutes for a warm startup, and 145 minutes for a hot startup while firing distillate oil.
>
> *Cold startup* means a startup to combined-cycle operation following a complete shutdown lasting more than 72 hours.
>
> *Warm startup* means a startup to combined-cycle operation following a complete shutdown lasting 8 hours or more, but less than or equal to 72 hours.
>
> *Hot startup* means a startup to combined-cycle operation following a complete shutdown lasting less than 8 hours.
>
> *Shutdown* means the period of time from MECL to when firing of fuel has ceased, not to exceed 60 minutes.
>
> *Fuel switching* means the period of time needed to change fuels during load operation without a complete shutdown, not to exceed 80 minutes.

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

EPD Review – CC Units NO_X Control

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

- USEPA RACT/BACT/LAER Clearinghouse[6]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

[6] https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en

The same resources have been utilized in preparing the Division's PM/PM_{10}/$PM_{2.5}$, SO_2, CO, Greenhouse Gases, H_2SO_4 and VOC BACT analyses.

After reviewing the RBLC Database, the Division has verified that the majority of the BACT controls on the combined cycle turbines have the use of DLN combustors, water injection, and SCR. Also, the limits of 2 ppmvd at 15% O_2 for natural gas combustion and 4 ppmvd at 15% O_2 for distillate oil combustion are common limits in the RBLC database, although the Plant's proposal of 5 ppmvd at 15% O_2 as a NO_X BACT limit when firing distillate oil due to their higher firing temperature is acceptable. The RBLC data has been examined for the last ten years for combined cycle combustion turbines.

<u>Conclusion – CC Units NO_X Control</u>

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

The BACT limits for the other facilities evaluated are similar to this Plant's proposed limits and the Division agrees with these limits. The Division agrees with the proposed BACT control technology of the use of SCR, ULSD, and dry-low NO_X burners for natural gas-fired operation and water injection for fuel oil-fired operation for NO_X control in the CC Units. The Division agrees with the proposed limits for normal operation. To account for emissions due to startup, shutdown or fuel switching, the Division has decided to include the Plant requested limit of 205.8 tons of NO_X emissions (12-consecutive month average) firing natural gas or distillate oil from each of the CC Units (Source Codes CT12/DB12 and CT13/DB13).

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-1:

Table 4-1: NO_X BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Fuel	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NO_X	DLN Combustors Water Injection SCR	Natural Gas	2.0 ppmvd @ 15% O_2	4 hours, rolling average	NO_X CEMS
		Distillate Oil	5.0 ppmvd @ 15% O_2		
		Both	205.8 tons*	12-consecutive months	NO_X CEMS

*Limit includes emissions during startup, shutdown, and fuel switching.

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – SO_2 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 SO_2 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 SO_2.

SO_2 Formation – CC Units

Emissions of SO_2 occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO_2 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 SO_2 Control Technologies – CC Units (Step 1)

The Plant reviewed SO_2 BACT determinations found in RBLC for large (>25 MW) natural gas fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS as having commenced commercial operation in 2019 and after or listed as planned and under construction in EIA-860. The results of these searches are summarized in Appendix 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 SO_2 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.[7] Instead, low sulfur fuels were chosen as the basis for the standards. Similarly, the use of low sulfur fuel is the basis of the SO_2 emission standard in NSPS Subpart KKKK, and EPA confirmed in the Subpart KKKKa rulemaking preamble that FGD is "not an applicable alternative for the control of SO_2 emissions" and does not reference the unreasonable cost of control.[8] Accordingly, use of fuels with inherently low sulfur content is the only potentially available control option for SO_2 emissions from the proposed CC units.

Elimination of Technically Infeasible SO_2 Control Options – CC Units (Step 2)

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

[7] 42 Fed. Reg. at 53782, 53785 (October 3, 1977)

[8] 89 Fed. Reg. at 101306, 101342 (December 13, 2024)

Summary and Ranking of Remaining SO_2 Controls – CC Units (Step 3)

No ranking of control options is required, as use of fuels with inherently low sulfur content is the only available and technically feasible control option for SO_2 emissions from the proposed CC units.

Evaluation of Most Stringent SO_2 Controls – CC Units (Step 4)

The top control option is being proposed for SO_2 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 SO_2 BACT – CC Units (Step 5)

Based on the Plant review, SO_2 BACT for the proposed CC units should be based on the use of fuels with inherently low sulfur content. Therefore, the Plant proposes the exclusive use of natural gas that meets the definition of pipeline quality natural gas as defined in 40 CFR 72.2 and distillate oil with a sulfur content less than 15 ppm, by weight, as SO_2 BACT for the proposed CC units. The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

EPD Review – CC Units SO_2 Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO_2 BACT analysis using the resources and information as discussed in the NO_X BACT review. The Division agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for SO_2.

Conclusion – CC Units SO_2 Control

The technically feasible control technologies for SO_2 emission control for combined cycle turbines are clean fuels. Therefore, clean fuels are the demonstrated and technically feasible options to be considered for this project. The Division agrees with the Plant's proposed use of clean fuels as BACT.

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-2:

Table 4-2: SO_2 BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO_2	Low Sulfur Content Fuels (Natural Gas, ULSD)	Natural gas, 0.5 grains sulfur/100 scf Ultra-low sulfur distillate oil (15 ppm sulfur)	N/A	Recordkeeping

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – CO Emissions

Applicant's Proposal

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

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

Identification of CO Control Technologies – CC Units (Step 1)
The Plant 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 summarized in Appendix D, Tables D-9 through D-12 of the application[9]. Potentially available control options to reduce CO emissions from the proposed CC units include combustion controls, good combustion practices, and post-combustion add-on controls such as an oxidation catalyst. Each is discussed in the following sections.

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

Oxidation Catalyst
An oxidation catalyst is a passive control option that uses excess air to convert CO emissions to CO_2 in the presence of catalyst without injection of a reagent. Technical considerations for employing this add-on control option include reactor design, operating temperature, back pressure of the system and its impact on performance, and catalyst life. Oxidation catalysts operate effectively in a relatively narrow temperature range typically between 600 to 800°F.

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

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

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

Summary and Ranking of Remaining CO Controls – CC 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 – CC Units (Step 4)

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

Selection of Emission Limits for CO BACT – CC Units (Step 5)

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

These results indicate CO emission limits for CC units with similar controls vary considerably and are as low as 0.9 ppmvd while firing natural gas and as low as 1.5 ppmvd while firing distillate oil (only emission limits up to 10 ppmvd are shown in the Figures). In many cases, the level of control depends on fuel, load, and whether duct burners are in-service (to account for supplemental firing in the HRSG). For both fuels, most emissions limits are 2 ppmvd.

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

- 2.0 ppmvd CO or less when firing natural gas or distillate oil based on a 24-hour rolling average, excluding periods of startup, shutdown, or fuel switching.

- 258.4 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching.

For both gas and distillate oil, the Plant is proposing 2 ppm as CO BACT, a level of control consistent with the majority of CO emission limits found for CC units. This level of control is also the same as Plant Barry Unit 8 (AL-0328) and JEC Units 1 and 2 (IL-0130), and therefore reflects the most stringent emission limit achieved in practice for similar CC units in commercial operation in the US. In most cases, permits issued to CC units with CO emissions limits that are more stringent than 2 ppmvd are associated with projects that were cancelled and never built, including Palmdale Energy Project (CA-1251), Killingly Energy Center (CT-0161), Chickahominy Power (VA-0332), ESC Tioga County Power (PA-0333), Renovo Energy Center (PA-0334), and

Nemadji Trail Energy Center (WI-0300 and WI-0326). In all but one of these cases (Chickahominy), the applicant proposed to construct a previous generation CT with inherently lower CO emissions in the CT exhaust (and inlet to the oxidation catalyst) relative to the proposed CC units. In the case of Chickahominy, while the CT technology would have been similar were it constructed, the applicant did not propose supplemental firing, i.e., duct burners, in the HRSG. Since an oxidation catalyst is a passive control that does not include injection of a reagent or other means to actively control emissions, CO BACT for the proposed CC units is necessarily higher to account for these differences.

Compliance with the CO BACT emission 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. The Plant notes that JEC's permit includes alternate CO limits that apply during low load operations, which are not included in the RBLC information.[10] 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 in additional emissions limitations, the Plant proposes that compliance with CO BACT be demonstrated on a 24-hour rolling average.

Similar to other CC units permitted by EPD, the Plant is proposing short-term 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 limit above, the following definitions apply:

> *Startup* means the period of time from when the combustion turbine is first fired to when the load has been achieved at which it has been demonstrated by a CEMS or during compliance testing that the emission limits can be met during steady-state operations (i.e., the minimum emissions compliance load or MECL), not to exceed 288 minutes for a cold startup, 212 minutes for a warm startup, and 131 minutes for a hot startup while firing natural gas and 315 minutes for a cold startup, 232 minutes for a warm startup, and 145 minutes for a hot startup while firing distillate oil.
>
> *Cold startup* means a startup to combined-cycle operation following a complete shutdown lasting more than 72 hours.
>
> *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.

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

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

EPD Review – CC Units CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis using the resources and information as discussed in the NO_X BACT review. The Division agrees that an oxidation catalyst, pipeline quality natural gas and ULSD fuel represent BACT control technology for CO.

Conclusion – CC Units CO Control

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

The BACT limits for the other facilities evaluated are similar to the Plant'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, clean fuels, and the use of good combustion practices for CO control in the CC Units.

The Division agrees with the proposed limits for normal operation. To account for emissions due to startup, shutdown or fuel switching, the Division has decided to include the Plant requested limit of 258.4 tons of CO emissions (12-consecutive month average) firing natural gas or distillate oil from each of the CC Units (Source Codes CT12/DB12 and CT13/DB13).

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-3:

Table 4-3: CO BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Fuel	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices	Natural Gas Or Distillate Oil	2.0 ppmvd @ 15% O_2	24 hours, rolling average	CO CEMS
	Oxidation Catalyst	Both	258.4 tons*	12-consecutive months	CO CEMS

*Limit includes emissions during startup, shutdown, and fuel switching.

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – VOC Emissions

Applicant's Proposal

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

VOC Formation – CC Units

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

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

The Plant reviewed VOC BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS as having commenced commercial operation in 2019 and after or listed as planned and under construction in EIA-860. The results of these searches are summarized in Appendix D, Tables D-13 through D-16 of the application.

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

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

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

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

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

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

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

Selection of Emission Limits for VOC BACT – CC Units (Step 5)

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

These results indicate VOC emission limits for CC units with similar controls vary considerably and are as low as 0.33 ppmvd (as propane) while firing natural gas and as low as 0.6 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 ppvmd 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 either fuel (and for gas when duct burners are in-service).

The Plant 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, and

- 2.0 ppmvd VOC or less, as methane, when firing natural gas with the 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, the Plant is proposing 1 ppmvd, as methane, as VOC BACT, a level of control consistent with the majority of VOC emission limits found for CC units and the same as JEC Units 1 and 2 (IL-0130). Similar to CO, permits issued to CC units with VOC emissions limits that are more stringent than 1 ppmvd are associated with projects that were cancelled and never built, including Killingly Energy Center (CT-0161), Rolling Hills Generating, LLC (OH-0365), C4GT, LLC (VA-0328), Chickahominy Power (VA-0332), and Nemadji Trail Energy Center (WI-0300 and WI-0326). Other facilities, such as West Deptford Energy Station (NJ-0082) and Greensville Power Station (VA-0325), are based on a smaller or previous generation of CT technology with inherently lower emissions. Birdsboro Power (NEEDS), which appears to have the most stringent gas-fired VOC limit at 0.33 ppmvd as propane for natural gas, is equivalent to the proposed VOC BACT when converted to an as-methane basis. Additionally, Nemadji, which appears to have the most stringent oil-fired VOC limit for fuel oil at 0.6 ppmvd, would have been based on a much longer 168-hour rolling average were the project constructed and permit not revoked.[11]

[11] https://www.nemadjitrailenergycenter.com/project-documents/AppB-NTEC-PSD-Application.pdf; https://www.wpr.org/news/utilities-withdraw-air-permit-gas-plant-proposed-superior https://apps.dnr.wi.gov/warp_ext/AM_PermitTracking2.aspx?id=28121

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

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

EPD Review – CC Units VOC Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the VOC BACT analysis using resources and information as discussed in the NO_X BACT review. The Division agrees that an oxidation catalyst, good combustion practices, pipeline quality natural gas and ULSD fuel represent BACT control technology for VOC.

Conclusion – CC Units VOC Control

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

The BACT limits for the other facilities evaluated are similar to this Plant'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, clean fuels, and the use of good combustion practices for VOC control in the CC Units. The Division agrees with the proposed limits for normal operation.

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-4:

Table 4-4: VOC BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Fuel	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Good Combustion Practices Oxidation Catalyst	Natural Gas	1.0 ppmvd (as methane) @ 15% O_2 (duct burner not in-service) 2.0 ppmvd (as methane) @ 15% O_2 (duct burner in-service)	N/A	3-run stack test Method 25A
		Distillate Oil	2.0 ppmvd (as methane) @ 15% O_2	N/A	3-run stack test Method 25A

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – $PM/PM_{10}/PM_{2.5}$ 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 $PM_{10}/PM_{2.5}$.

PM Formation – CC Units

PM emissions from the proposed CC units include both filterable and condensable particles.[12] Filterable PM is formed from impurities contained in fuels, dust in the ambient air, and from incomplete combustion, while condensable PM is primarily attributable to high molecular weight VOC (unburned hydrocarbons) and the conversion of fuel sulfur to sulfates when catalyst-based add-on controls are used.

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

For PM, the Plant also reviewed BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS or EIA-860. The results of these searches are summarized 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.[13]

With the BACT context, these emission controls have no practical potential to reduce emissions from the proposed CC units because the use of clean fuels inherently results in a low level of PM emissions. For example, the outlet performance specification of a typical baghouse or electrostatic precipitator is 0.01 gr/dscf.[14] Based on information provided in Appendix C of the application, the

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

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

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

total concentration of PM emissions, including condensable PM, from the proposed CC units is expected to range from approximately 0.002 to 0.004 gr/dscf, depending on the fuel being utilized, which is nearly an order of magnitude lower than what these control options typically achieve. Accordingly, these controls need not be listed in Step 1 of the BACT analysis. However, even if listed in Step 1, these control options would be eliminated as technically infeasible in Step 2 for essentially the same reason—they have no real potential to reduce PM emissions from the proposed CC units.[15] Therefore, only the use of fuels with inherently low sulfur content and good combustion practices are considered further.

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

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

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

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

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

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

Selection of Emission Limits for PM BACT – CC Units (Step 5)

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

- Total PM, containing filterable and condensable PM, equal to or less than 0.0044 lb/MMBtu, when firing natural gas, based on the average of a 3-run stack test using EPA Reference Methods 5 and 202, and

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

The proposed PM BACT reflects approximately 0.002 lb/MMBtu filterable PM when firing gas, 0.01 lb/MMBtu when firing distillate oil, and full conversion of the sulfur in fuel to inorganic sulfate-based condensable PM. In establishing BACT, full conversion of sulfur to sulfates is

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

appropriate since vendors do not offer guarantees to limit sulfur conversion to SO_3 in the CT and HRSG and there are sufficient amounts of moisture and ammonia in the exhaust to complete sulfate formation, even at extremely low levels of ammonia slip (<0.3 ppmvd).

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

However, after additional research, the Plant notes that many of the PM emissions limits found for CC units that are lower than the proposed BACT: (1) are not total PM, but filterable only and do not include condensable PM, 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 PM2.5 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).[16]

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

<u>EPD Review – CC Units PM/PM_{10}/$PM_{2.5}$ Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM BACT analysis using resources and information as discussed in the NO_X BACT review. The Division agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for PM/PM_{10}/$PM_{2.5}$.

<u>Conclusion – CC Units PM/PM_{10}/$PM_{2.5}$ Control</u>

The technically feasible control technologies for PM emission control for combined cycle turbines are clean fuels. Therefore, clean fuels are the demonstrated and technically feasible options to be considered for this project. The Division agrees with the Plant's proposed use of clean fuels as BACT and agrees with the proposed limits.

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-5:

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

Table 4-5: PM BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Fuel	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Low Sulfur Content Fuels	Natural Gas	0.0044 lb/MMBtu	N/A	3-run stack test Method 5 Method 202
		Distillate Oil	0.0135 lb/MMBtu	N/A	3-run stack test Method 5 Method 202

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – Sulfuric Acid Mist (H_2SO_4) Emissions

Applicant's Proposal

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

SAM Formation – CC Units

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

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

For SAM, the Plant also reviewed BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS or EIA-860. The results of these searches are summarized 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 inherently low sulfur content results in a low level of emissions (approximately 0.2 ppmvd in the exhaust gas).

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

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

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

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

Evaluation of Most Stringent SAM Controls – CC 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 control options is required.

Selection of Emission Limits for SAM BACT – CC Units (Step 5)

Based on the Plant review, SAM BACT for the proposed CC units should be based on the use of fuels with inherently low sulfur content. Therefore, the Plant proposes the exclusive use of natural gas that meets the definition of pipeline quality natural gas as defined in 40 CFR 72.2 and distillate oil with a sulfur content less than 15 ppm, by weight, as 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 – CC Units SAM Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SAM BACT analysis using the resources and information as discussed in the NO_X BACT review. The Division agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for SAM.

Conclusion – CC Units SAM Control

The technically feasible control technologies for SAM emission control for combined cycle turbines are clean fuels. Therefore, clean fuels are the demonstrated and technically feasible options to be considered for this project. The Division agrees with the Plant's proposed use of clean fuels as BACT.

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-6:

Table 4-6: H_2SO_4 BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
H_2SO_4	Low Sulfur Content Fuels (Natural Gas, ULSD)	Natural gas, 0.5 grains sulfur/100 scf Ultra-low sulfur distillate oil (15 ppm sulfur)	N/A	Fuel Supplier Documentation

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – GHG Emissions – CO_2

Applicant's Proposal

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

Greenhouse Gases – CO_2 Formation – CC Units

GHG emissions that result from combustion include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).[17] 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:

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

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

Identification of Greenhouse Gases – CO_2 Control Technologies – CC Units (Step 1)

As with the other BACT reviews above, the Plant reviewed CO_2 BACT determinations found in RBLC for large (>25 MW) natural gas-fired and distillate oil-fired CC units permitted since 2014, and also reviewed permits and associated applications, if available, for other CC units not found in RBLC but identified in NEEDS and EIA-860. Based on these search results, no add-on control options were identified in RBLC or in any permit or application. However, many facilities listed inherently lower-emitting processes and practices as BACT, including some variation of use of clean or lower-emitting fuels, efficient design, and good combustion practices as BACT for CO_2 emissions. These results are summarized in Appendix D, Tables D-23 and D-24 of the application.

The Plant also considered relevant federal and state emission standards and relied on Southern Company's experience as a leader in low-carbon technology research and innovation to identify additional potential control options for CO_2 emissions from the proposed CC units. EPA's 2023 proposed GHG emissions standards identified co-firing low GHG-hydrogen as a potential control option,[18] although this control option was not included in the final regulations adopted in Subpart TTTTa.[19] EPA's final emission GHG standards in Subpart TTTTa, which are potentially

[17] Comparatively very small emissions of CH_4 and N_2O 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.

[18] 88 Fed. Reg. at 33284 (May 23, 2023).

[19] 40 CFR Part 60, Subpart TTTTa.

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.[20] Nonetheless, more solar and energy storage resource procurement and customer programs have been proposed to the Georgia Public Service Commission (PSC) as part of the Plant'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 fuels are referred to variously as "clean fuels" in Subpart TTTT and as "lower-emitting fuels" in Subpart TTTTa.

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

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

Use of Low-GHG Hydrogen
In its 2023 proposed GHG emissions standards, EPA proposed co-firing 30% low-GHG hydrogen by 2032 as BSER for both intermediate load and baseload CT units, with an increase to 96% low-GHG hydrogen by 2038 for baseload units. Low-GHG hydrogen requires the production of hydrogen through use of a low CO_2 emission technology, such as a renewable energy-powered process or a fossil fuel-powered process paired with CCS. Notably, co-firing low-GHG hydrogen was not included in the final standards due to significant uncertainties related to the availability and cost-effectiveness of this control option.[21] Co-firing low-GHG hydrogen is nonetheless evaluated as a potential control option in this BACT analysis based on its inclusion in the proposal.

Carbon Capture and Storage
While EPA removed co-firing low-GHG hydrogen from the final rules in Subpart TTTTa, it did base the final standards for some CT units, in part, on CCS. Therefore, CCS is evaluated as a potential control option in this BACT analysis. CCS requires the integration of a variety of processes and equipment to separate and capture CO_2 from the exhaust stream, compress and

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[20] 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).

[21] 89 Fed. Reg. at 39939 (May 9, 2024).

transport the CO_2 to a suitable geologic storage location and pump the CO_2 deep underground. Notably, EPA's determination in Subpart TTTTa that CCS is BSER for some combustion turbines is the subject of litigation currently underway in the U.S. Circuit Court of Appeals for the D.C. Circuit,[22] and EPA has also proposed to repeal the CCS requirements in Subpart TTTTa.[23]

Based on the discussion above, the following potential control options for CO_2 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.

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

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

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

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

Waste heat recovery in the HRSG also represents efficient design. These heat exchangers are designed to capture thermal energy from CT exhaust gases and duct burners, using this heat to

[22] *West Virginia v. EPA*, No. 24-1120.

[23] 90 Fed. Reg. 25752 (June 17, 2025)

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

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

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

The proposed CT units will also be maintained following a maintenance program recommended by the original equipment manufacturer (OEM). Maintenance programs are important for efficiency as well as long-term reliability and are based on a schedule determined by the number of hours of operation and/or turbine starts. Such programs commonly include three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles and include combustor tuning to maintain highly efficient, low-emissions operation. Hot gas path inspections and major inspections occur on manufacturer-prescribed schedules and involve inspection and possible replacement of internal parts, including compressor or turbine blades, to restore as much lost performance as possible.

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

Based on the above, use of good combustion, maintenance, and operating practices is available, applicable to the Project, and thus technically feasible.

Use of Low-GHG Hydrogen
Hydrogen co-firing is a promising, but still emerging, technology. However, for purposes of a BACT determination, low-GHG hydrogen is not technically feasible because it is neither "available" nor "applicable" 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, the 2025 One Big Beautiful Bill Act (OBBBA) froze IIJA funding and accelerated the repeal of many clean energy tax credits introduced in the IRA, including those under Section 45V of the Internal Revenue Code (IRC) for hydrogen. While the US Department of Energy (DOE) previously announced $7 billion in funding to launch seven Regional Clean Hydrogen Hubs (H2Hubs) across the nation, none will be located in Georgia or in the southeastern US,[24] and DOE recently began reducing or terminating funding for projects.[25] The Plant is unaware of any plans to build out the significant infrastructure necessary to make low-GHG hydrogen a commercially available control option. Even if sufficient supply were available, there are insufficient pipelines to transport low-GHG hydrogen to customers since pipeline gas quality specifications, in particular higher heating value (HHV), prevent blending the volumes of hydrogen that would be required into the existing natural gas infrastructure.[26] 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 CCs, including one of the units at the 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.[27] Moreover, the test burns that have been conducted have 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 did not use low-GHG hydrogen, the tests do not indicate that this control option is available and applicable. According to EPA guidance, applicants need not consider "technologies which have not yet been applied to (or permitted for) full scale operations."[28] Since hydrogen co-firing has not been demonstrated in practice, it does not constitute a demonstrated and applicable control technology for the proposed CC units. Accordingly, low-GHG hydrogen is not technically feasible.

Carbon Capture and Storage

Carbon capture and storage (CCS) is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for 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

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[24] https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.

[25] https://www.eenews.net/articles/doe-cancellations-hit-hydrogen-air-capture-hubs/.

[26] The pipeline specification is 950 Btu/scf HHV. See Southern Natural Gas Company, LLC, FERC Tariff, Eighth Revised Volume No.1, Part IV - General Terms and Conditions, Section 3 – Quality, 3(f). For example, blending 30% low-GHG hydrogen with natural gas results in a heating value of approximately 810 Btu/scf. However, the pipeline specification applies to the gas offered at the point of delivery (e.g., just upstream of the point of injection), making direct injection of hydrogen impossible.

[27] For example, the short-term test burns at Plant McDonough have been conducted up to a maximum of approximately 50% 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.

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

suite of components must also be technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the units.[29] Accordingly, any potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

Capture and Compression

There are two CCS systems currently installed and operational at commercial power plants in North America: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova project in Texas. However, both of these projects are coal-fired steam units, both are comparatively small, and both have experienced significant technical and operational hurdles that have prevented continuous successful operation, as would be required for a typical power plant. Boundary Dam is a 110 MW coal-fired unit that was designed for but has proven incapable of capturing up to 90 percent of its CO_2 emissions using an amine solvent. While Boundary Dam has captured over six million metric tons of CO_2 since carbon capture operations began in 2014, this represents less than 63% percent of the one million tons per year goal, or a carbon capture rate of only 57%.[30] Furthermore, it has experienced ongoing equipment issues that have negatively impacted the unit's ability to consistently capture CO_2. Similarly, the Petra Nova project was designed to capture 90 percent of the CO_2 emissions of a 240 MW slip stream from a 610 MW coal-fired unit (approximately 35 percent of the unit's total CO_2 emissions) to be used for enhanced oil recovery. In its three years of operation, Petra Nova missed its carbon capture target by about 17 percent relative to what developers had expected and the project was discontinued in 2020 due to lack of economic viability, although Petra Nova recently restarted in the latter half of 2023. During the prior period of system operation, Petra Nova experienced outages on 367 days, with the CCS Plant accounting for more than one-fourth of those outage days.[31] Additionally, the Petra Nova capture system was powered by a separate gas-fired combustion turbine, and the CO_2 emissions from the turbine were not captured, which materially reduced the actual net emissions reductions from the project.

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

In addition to the types of carbon capture technology employed at Boundary Dam and Petra Nova and being examined in FEED studies, there are other carbon capture technologies that are under development, such as polymeric membranes, combination solvent/membranes, and solid sorbents. Polymeric membranes have shown potential for carbon capture from coal-fired flue gas streams but are challenged by the lower CO_2 partial pressures/concentrations from CC units. Combination solvent/membrane systems are not yet ready for demonstration. Solid sorbents are likewise developing technologies but also not yet demonstrated at relevant scale.

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

[30] https://ieefa.org/resources/carbon-capture-boundary-dam-3-still-underperforming-failure.

[31] https://www.reuters.com/article/business/environment/problems-plagued-us-co2-capture-project-before-shutdowndocument-idUSKCN2523K7/

While there has been significant progress made in the development of carbon capture systems for coal-fired steam electric generating units, carbon capture technology has not been adequately demonstrated at scale for simple- or combined-cycle combustion turbines. In CTs, whether in simple- or combined-cycle configurations, a significant portion of the air drawn into the compressor is not used for combustion, but for cooling various internal components, including the combustor and turbine blades. This, coupled with the combustion of clean, or lower-emitting fuels such as natural gas or distillate oil, results in a dilute gas stream with inherently low concentrations of CO_2, making CO_2 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 CO_2 gas streams at the same stationary source.[32]

Technology testing at the National Carbon Capture Center (NCCC) and the Technology Centre Mongstad (TCM) (located in Mongstad, Norway), focused primarily on use of amine solvents, has been valuable to evaluate carbon capture technologies and move them through development to prepare for future potential demonstration.[33] Several technologies that have been tested at those facilities are now in the Front-End Engineering Design (FEED) stage, which refines the expected costs of those options. Nevertheless, a technology must be adequately demonstrated at a scale beyond the NCCC or TCM to identify and address operational issues before being considered commercially available. Many of these projects are now advancing and have been selected for follow-on pilot and demonstration projects,[34] but commercial application of these projects will remain unproven for years. The Plant is aware of a permit been issued for CCS to the CC units located at CPV Basin Ranch Holding, Inc. in Ward, Texas, but this CCS system has not yet been constructed.[35] 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."

Southern Company recently participated in two DOE-funded FEED studies for retrofitting CO_2 capture on a CC unit, excluding the CO_2 transportation pipelines and storage facilities that would be required to permanently sequester the CO_2 underground. The first FEED study used Mississippi Power's Plant Daniel Unit 4 combined-cycle Plant as the host site to study a retrofit of Linde-BASF's post-combustion capture technology with a target of 90 percent CO_2 capture. The project team developed the retrofit design to a level of detail sufficient to support an Association for the

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[32] Wabash Valley Resources (RBLD Id. IN-0371) plans to redevelop an existing coal gasification plant in West Terre Haute, Indiana (formerly the Duke Energy Wabash River Station) to make hydrogen for sale or use as feedstock in the production of anhydrous ammonia fertilizer. https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-gasification-doe-fecm.pdf. The developers plan to produce blue hydrogen by incorporating CCS downstream of the sweet gas water shift reaction, which would create a gas stream with high concentrations of CO_2 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, CO_2e BACT Analysis – 2,292 MMBtu/hr IGCC CT.

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

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

[35] The permit does not identify CCS as BACT for the Plant.

Advancement of Cost Engineering (AACE) Class 3 cost estimate with an associated project schedule, including detailed design, procurement, construction, commissioning, and startup, estimated at roughly five years. The Plant Daniel FEED study took approximately 2 years to complete before concluding in 2022. The final project report is publicly available through the DOE's Office of Science and Technical Information (OSTI).[36]

The second FEED study project used Alabama Power's Plant Barry Unit 6 combined-cycle Plant as the host site to apply a retrofit of Linde-BASF's post-combustion technology with a target of 95 percent CO_2 capture. This retrofit design included more complex integration of the carbon capture system with a CC unit, including exhaust gas recirculation (EGR), which recycles a portion of the exhaust gas from the heat recovery steam generator (HRSG) to the inlet of the combustion turbine, thus increasing the exhaust gas CO_2 concentration and decreasing the volume of gas to be treated in the CO_2 capture process. Both of these improvements should decrease the size of CO_2 capture equipment and improve efficiency of CO_2 capture. Similar to the Plant Daniel project, the project team developed a cost estimate and schedule and completed the work in March 2024. The final report was released through OSTI October 15, 2024.[37]

Participating in these FEED studies has provided significant insight into the technical and logistical aspects of integrating CO_2 capture on a CC unit. Equally as important, these FEED studies have revealed and highlighted areas where more detailed work and experience is needed to understand the operating, maintenance, and reliability impacts of a CC unit with CCS on the electric grid, particularly with respect to non-steady state operating conditions. As recognized by Congress through the IIJA (Infrastructure Investment and Jobs Act) and subsequent DOE (Department of Energy) FOAs (Funding Opportunity Announcements), the next step in application of CCS on combustion turbines should include execution of demonstration projects to further define the operating flexibility and reliability of these units. To date, none of the CCS projects identified at combined-cycle units have yet progressed to a complete detailed design or full deployment and thus cannot be the basis of a BACT determination for the Project.

Storage

Once captured, CO_2 must be stored underground in suitable geological formations, but not all regions of the U.S. have the required geology. In 2024, GPC performed boring projects to better understand the geologic formations in Georgia and assess the viability of safe and permanent storage of CO_2. That work indicates that Southeast Georgia may have favorable geology, but determination of the overall feasibility remains many years away and requires more due diligence, including extensive site-specific investigations and testing performed in accordance with EPA's Class VI permitting process. Developers, such as Carbon America, also intend to further explore Georgia's geology and its potential for CO_2 storage.[38]

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[36] Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant, U.S. Department of Energy, Office of Fossil Energy and Carbon Management (FECM), National Energy Technology Laboratory, DE-FE0031847. Available at https://www.osti.gov/servlets/purl/1890156/.

[37] Retrofittable Advanced Combined Cycle Integration for Flexible Decarbonized Generation. Available at https://www.osti.gov/servlets/purl/2377996

[38] Carbon America's Project Antheia is one of 23 projects being funded by the 2021 Infrastructure Investment and Jobs Act, in support of the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative and selected for Phase III carbon storage validation and testing. https://www.energy.gov/fecm/project-selections-foa-2711-carbon-storage-validation-and-testing-round-3.

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 CO_2 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 CO_2 via pipeline to a storage location is an essential component of CCS where storage or an available use of the CO_2 is not available at the site. Only a few pipelines are currently used to carry CO_2 in the U.S., primarily linking natural sources of CO_2 sources to oil fields for use in enhanced oil recovery (EOR). However, a national CO_2 pipeline network does not exist, which makes this critical step in the CCS process unavailable in many areas of the country. The only announced proposed CO_2 pipelines under development for CCS have been in the Midwest U.S., spanning the states of Illinois, Iowa, Minnesota, Nebraska, North Dakota, and South Dakota. However, the majority of these projects have been cancelled or delayed.[39] There are no existing or planned networks in Georgia. So, while CO_2 transportation via pipeline has been physically demonstrated, CO_2 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, the availability of storage has not yet been fully determined, and transportation of CO_2 to offsite locations is not available, CCS is not technically feasible for the Project.[40][41]

As EPA states in its GHG BACT Guidance, "CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. … Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base Plant and site-specific considerations." The above analysis is consistent with this guidance—CCS has only been applied at commercial scale to coal-fired units, not gas-fired turbines, and the difference in the nature of the exhaust stream of a combustion turbine compared to a coal-fired unit presents significant unresolved challenges that make the application of CCS to this project technically infeasible.

[39] https://www.rabobank.com/knowledge/d011434507-the-long-haul-to-long-haul-carbon-dioxide-pipeline-development-in-the-us.

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

[41] For purposes of this BACT analysis, consideration of CCS also includes partial CCS as a potential control alternative. However, the analysis determined that partial CCS presents the same challenges as full CCS with respect to availability and applicability under Step 2. Therefore, since full CCS was determined to be infeasible in Step 2, the same conclusions were reached for partial CCS as well. Accordingly, this analysis does not expressly include additional details on the evaluation of partial CCS as a potential control option.

Summary and Ranking of Remaining Greenhouse Gases – CO_2 Control Technologies – CC Units (Step 3)

Use of clean/low-emitting fuels, efficient design, and good combustion, operating, and maintenance practices are the only available and technically feasible control options for CO_2 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 – CO_2 Control Technologies – CC Units (Step 4)

The top control option is proposed for emissions of CO_2 from the proposed CC units. Therefore, no further evaluation of the CO_2 control options is required.

Selection of CO_2 BACT for Greenhouse Gases – CC Units (Step 5)

Based on the Plant review, CO_2 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. RBLC search results, summarized in Appendix D, Tables D-23 and D-24 of the application, indicate that the most common form of CO_2 emissions limit for the type of source under consideration is a 12-month rolling average emission rate on a lb CO_2/MWh-gross basis. Based on the Plant's review of the search results and the potentially applicable regulations in Subpart TTTTa:

- The level of control for all CC units of a similar configuration, i.e., 1-on-1, without regard to CT technology, operating mode, or fuel, ranges from 726 to 1,384 lb CO_2/MWh-gross with an average emission limit of approximately 900 lb CO_2/MWh-gross.

- Emission limits for 1-on-1 CC units that are greater than 1,000 lb CO_2/MWh-gross apply only while burning oil or while operating at low loads.[42]

- Emissions limits for 1-on-1 CC units that are less than 800 lb CO_2/MWh-gross are based on operating at full load without use of duct burners while burning natural gas only.[43] Otherwise, these units are subject to the Subpart TTTT emission limit of 1,000 lb CO_2/MWh-gross.

- Emission limits for all dual-fuel 1-on-1 CC units range from 850 and 1,384 lb CO_2/MWh-gross when separate limits apply depending on the fuel being burned.[44] However, when a single limit applies without regard to the fuel burned, the range for

[42] CPV Three Rivers (IL-0129) and Nemadji Trail Energy (WI-0300) have emission limits of 1,384 and 1,180 lb CO_2/MWh-gross, respectively, when burning oil. JEC Units 1 and 2 (IL-0130) have an emission limit of 1,190 lb CO_2/MWh-gross when operating at low loads.

[43] 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)

[44] 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 52.

dual-fuel 1-on-1 CC units narrows to between 888 and 1,000 lb CO_2/MWh-gross, where the upper bound is the emission limit in Subpart TTTT.[45]

- The potentially applicable regulations in Subpart TTTTa establish a "sliding-scale" emission standard which, for large CTs, ranges from 800 to 1,067 lb CO_2/MWh-gross depending on how much distillate oil was used in the previous 12 operating months.

Based on the above, the Plant proposes the following as CO_2 BACT:

- 900 lb CO_2e/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.[46] 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 CH_4 and N_2O based on the BACT determinations for those pollutants, which are summarized below.

Compliance with the proposed GHG BACT limit will be demonstrated by continuously monitoring heat input according to 40 CFR Part 75, Appendix D, and using emission factors to calculate monthly emissions. The emission factor for CO_2 will be based on 40 CFR Part 75, Appendix G, Eq. G-4. while emissions of CH_4 and N_2O will be based on the current emission factors in 40 CFR Part 98, Table C-2[47] and the current global warming potentials in 40 CFR Part 98, Table A-1 (1, 28, and 265 for CO_2, CH_4, and N_2O, respectively).[48]

EPD Review – CC Units Greenhouse Gases – CO_2 Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the GHG BACT analysis using the resources and information as discussed in the NO_X BACT review. The Division agrees that the use of clean/low-emitting fuels, efficient design, and good combustion, operating, and maintenance practices represents BACT control technology for GHG and agrees with the proposed limit.

[45] While CPV, Nemadji, and Middlesex are dual-fuel units, only Middlesex has a single limit that includes emissions from burning both natural gas and distillate oil. The Middlesex limit of 888 lb CO_2/MWh-gross includes 720 hours per year of operation on oil.

[46] The proposed CO_2e BACT limit of 900 lb CO_2e/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.

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

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

Conclusion – CC Units Greenhouse Gases – CO_2 Control

The BACT selection for the CC Units (Source Codes CT12/DB12 and CT13/DB13) is summarized below in Table 4-7:

Table 4-7: GHG BACT Summary – CC Units (Source Codes CT12/DB12 and CT13/DB13)

Pollutant	Control Technology	Fuel	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Clean/Low Emitting Fuels Efficient Design Good Combustion, Operating, and Maintenance Practices	Natural Gas and Distillate Oil	900 lb CO_2e/MWh-gross	12-month rolling average*	CEMS

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

Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – GHG Emissions – CH_4

Greenhouse Gases – CH_4 Emissions Formation – CC Units

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

Applicant's Proposal

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

Identification of Greenhouse Gases – CH_4 Control Technologies – CC Units (Step 1)

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

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

Elimination of Technically Infeasible Greenhouse Gases – CH_4 Control Technologies – CC Units (Step 2)

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

Summary and Ranking of Remaining Greenhouse Gases – CH_4 Control Technologies – CC Units (Step 3)

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

Evaluation of Most Stringent Greenhouse Gases – CH_4 Control Technologies – CC Units (Step 4)

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

Selection of BACT for Greenhouse Gases – CH_4 – CC Units (Step 5)

Good combustion practices are selected as BACT for CH_4 emissions from the proposed CC units. The Plant is proposing that a separate numerical limit for CH_4 emissions is unnecessary because CH_4 emissions are included in the proposed GHG limit expressed in CO_2e determined to be BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 28 (per 40 CFR 98 Subpart A, rule effective January 1, 2025).

EPD Review – CC Units Greenhouse Gases – CH_4 Control

For the proposed CC units, the contribution of CH_4 to total CO_2e emissions is negligible and therefore should not warrant a detailed BACT review.

Conclusion – CC Units Greenhouse Gases – CH_4 Control

Because methane is an insignificant fraction of the overall greenhouse gas emissions, it is assumed that the contributions from methane are included in the monitored emissions and corresponding limit. Refer to the review for Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – GHG Emissions – CO2.

<u>Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – GHG Emissions – N_2O</u>

<u>Greenhouse Gases – N_2O Emissions Formation – CC Units</u>

There are five (5) primary pathways of NO_X production in combustion turbines: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using DLN combustors, the N_2O pathway is the prevailing mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with N_2O, creating N_2 and NO.[49] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed, the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like those in DLN combustors are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream, all of which are common NO_X control measures.[50] Therefore, reductions in NO_X can result in incremental increases in N_2O emissions.

<u>Applicant's Proposal</u>

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

<u>Identification of Greenhouse Gases – N_2O Control Technologies – CC Units (Step 1)</u>

Good combustion practices are an available control option to reduce N_2O emissions from the proposed CC units. As discussed above, N_2O formation is limited during complete combustion, since most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG. Additionally, N_2O catalysts are a potential control option, as they have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[51] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with an N_2O catalyst followed by ammonia injection and a NO_X catalyst.

<u>Elimination of Technically Infeasible Greenhouse Gases – N_2O Control Technologies – CC Units (Step 2)</u>

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

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

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

N_2O catalyst providers do not offer products to control N_2O emissions from combustion turbines due to the very low N_2O concentrations present in exhaust streams (approximately 5 ppm).[52] Since N_2O catalysts are not available, good combustion practices are the only available control option and are technically feasible.

Summary and Ranking of Remaining Greenhouse Gases – N_2O Control Technologies – CC Units (Step 3)

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

Evaluation of Most Stringent Greenhouse Gases – N_2O Control Technologies – CC Units (Step 4)

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

Selection of BACT for Greenhouse Gases – N_2O CC Units (Step 5)

Good combustion practices are selected as BACT for N_2O emissions from the proposed CC units. The Plant is proposing that a separate numerical limit for N_2O emissions is unnecessary because N_2O emissions are included in the proposed GHG limit expressed in CO_2e determined to be BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 265 (per 40 CFR 98 Subpart A, rule effective January 1, 2025).

EPD Review – CC Units Greenhouse Gases – N_2O Control

For the proposed CC units, the contribution of N_2O to total CO_2e emissions is also negligible and therefore should not warrant a detailed BACT review.

Conclusion – CC Units Greenhouse Gases – N_2O Control

Because N_2O is an insignificant fraction of the overall greenhouse gas emissions, it is assumed that the contributions from methane are included in the monitored emissions and corresponding limit. Refer to the review for Combined-Cycle Units (Source Codes CT12/DB12 and CT13/DB13) – GHG Emissions – CO2.

[52] 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 Towers – BACT Review

Cooling Towers – PM Emissions

Applicant's Proposal

PM Formation

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

Identify Control Options for Evaluation – Cooling Towers (Step 1)

The Plant 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.

Eliminate Technically Infeasible Control Options – Cooling Towers (Step 2)

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

Rank Remaining Control Options – 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.

Evaluate Remaining Control Options – 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.

Select BACT – Cooling Towers (Step 5)

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

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

EPD Review – Cooling Towers PM Control

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

Conclusion – Cooling Towers PM Control

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

Table 4-8: PM BACT Summary – Cooling Towers

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

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – BACT Review

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – NO_X Emissions

Applicant's Proposal

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 the heaters.

Identification of NO_X Control Technologies – Heaters (Step 1)

The Plant 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, Table D-26 of the application, 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, SNCR, and non-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.

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

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

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.

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

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

<u>Selection of Emission Limits for NO_X BACT – Heaters (Step 5)</u>

Based on the Plant review, 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 RBLC search results, NO_X emission limits for natural gas-fired fuel gas heaters with a heat input rating of less than 10 MMBtu/hr range from 0.011 to 0.149 lb/MMBtu.

Considering this information, the Plant is proposing a NO_X BACT limit of 9 ppmvd, corrected to 3% O_2, or 0.011 lb/MMBtu, to be demonstrated by monitoring NO_X emissions while emissions of

CO are optimized during biennial tune-ups under the Industrial Boiler MACT (40 CFR Part 63, Subpart DDDDD).[53] Measurements of NO_X (and O_2) will be conducted using the procedures of ASTM D 6522, CTM-030, or EPA Reference Methods 7E and 3A.

EPD Review – Heaters 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.[54]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.

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

Conclusion – Heaters NO_X Control

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

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

- Colbert Combustion Turbine Plant, 10 MMBtu/hr, 0.011 lb/MMBtu
- Chickahominy Power, LLC, 0.011 lb/MMBtu
- Jackson Energy Center, 96 MMBtu/hr, 0.010 lb/MMBtu

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

The BACT selection for the fuel gas heaters is summarized below in Table 4-9:

Table 4-9: NO_X BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NO_X	Natural Gas, Good Combustion Practices, and Ultra-Low NO_X Burners	9.0 ppmvd @ 3% O_2, or 0.011 lb/MMBtu	N/A	Biennial tune-up

[53] 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.

[54] https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – SO_2 Emissions

Applicant's Proposal

SO_2 Formation – Heaters

Emissions of SO_2 occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO_2 emissions associated with combustion of natural gas are very low due to the low concentration of sulfur compounds in the fuel.

Identification of SO_2 Control Technologies – Heaters (Step 1)

For SO_2, the Plant 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 SO_2 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 a low level of emissions.

Elimination of Technically Infeasible SO_2 Control Options – Heaters (Step 2)

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

Summary and Ranking of Remaining SO_2 Control Options – Heaters (Step 3)

No ranking of control options is required, as used of fuels with inherently low sulfur content is the only available and technically feasible control option for SO_2 emissions from the proposed fuel gas heaters.

Evaluation of Remaining SO_2 Control Options – Heaters (Step 4)

The top control option is being proposed for SO_2 emissions from the proposed fuel gas heaters. No further evaluation of the energy, environmental, and economic impacts of the control options is required.

Selection of Emission Limits for SO_2 BACT (Step 5)

Based on the Plant review, SO_2 BACT for the proposed heaters should be based on the use of fuels with inherently low sulfur content. Therefore, the Plant proposes the exclusive use of natural gas that meets the definition of pipeline quality natural gas as defined in 40 CFR 72.2 as SO_2 BACT for the proposed heaters. The sulfur content of each fuel will be verified periodically through documentation provided by the supplier.

EPD Review – Heaters SO_2 Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO_2 BACT analysis using the resources and information as discussed in the NO_X BACT review. The Division agrees that the exclusive use of pipeline quality natural gas represents BACT control technology for SO_2.

Conclusion – Heaters SO_2 Control

The technically feasible control technologies for SO_2 emission control for fuel gas heaters are low sulfur content fuels. Therefore, low sulfur content fuels are the demonstrated and technically feasible options to be considered for this project. The Division agrees with the Plant's proposed use of natural gas as BACT.

The BACT selection for the fuel gas heaters is summarized below in Table 4-10:

Table 4-10: SO_2 BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO_2	Low Sulfur Content Fuel	Exclusive use of natural gas	N/A	Fuel Records

Fuel Gas Heaters (Source Codes) – CO Emissions

Applicant's Proposal

CO Formation – Heaters

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

Identification of CO Control Technologies – Heaters (Step 1)

The Plant searched 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 CO_2. Based on the RBLC search results provided in Appendix D, Table D-28 of the application, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices (e.g., tune-ups). Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

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

Use of Clean Fuels and Good Combustion Practices
Use of natural gas and good combustion practices are inherent to the Project and technically feasible.

Oxidation Catalyst
Oxidation catalysts are add-on controls which convert emissions of CO to CO_2 in the presence of a catalyst without the addition of any chemical reagent. The Plant is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed water bath heaters. As discussed above, only combustion controls for NO_X emissions from small process heaters are commercially available. Therefore, oxidation catalysts are not technically feasible.

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 – Heaters (Step 5)

Based on the Plant review, CO BACT for the proposed fuel gas heaters should be 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 Plant lists fuel gas heaters that have emission limits for both of these pollutants (AL-0329).[55] The CO emission limit for these fuel gas heaters is 0.080 lb/MMBtu,[56] when limited to 0.011 lb/MMBtu for NO_X emissions consistent with the BACT determination as proposed above.

Based on this information, the Plant is proposing a CO BACT limit of 100 ppmvd, corrected to 3% O_2, or 0.074 lb/MMBtu, to be demonstrated by using a portable analyzer to monitor emissions of CO during biennial tune-ups under the Industrial Boiler MACT (40 CFR Part 63, Subpart DDDDD).[57] Measurements of CO (and O_2) will be conducted using the procedures of ASTM D 6522, CTM030, or EPA reference methods 10 and 3A.

[55] Tennessee Valley Authority, Colbert Combustion Turbine Plant.

[56] Based on a 3-hour averaging time using EPA Reference Method 10.

[57] *Id.*

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 using the resources and information as discussed in the NO_X BACT review.

Conclusion – Heaters CO Control

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

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

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

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

The BACT selection for the fuel gas heaters is summarized below in Table 4-11:

Table 4-11: CO BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Natural Gas and Good Combustion Practices	100 ppmvd @ 3% O_2, or 0.074 lb/MMBtu	N/A	Biennial tune-up

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – VOC Emissions

Applicant's Proposal

VOC Formation – Heaters

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

Identification of VOC Control Technologies – Heaters (Step 1)

The Plant 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, Table D-29 of the application, 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 CO_2 in the presence of a catalyst without the addition of any chemical reagent. The Plant is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. 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– Heaters (Step 5)

Based on the Plant's review, VOC BACT for the proposed fuel gas heaters should be 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. However, 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% O_2, or 0.010 lb/MMBtu. However, instead of a numerical BACT limit, the Plant is proposing the exclusive use of natural gas and optimizing emissions of CO during biennial tune-ups required by the Industrial Boiler MACT (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 using the resources and information as discussed in the NO_X BACT review.

Conclusion – Heaters VOC Control

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

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

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

The limits for other facilities evaluated above are similar to those reviewed by the Plant. The Division agrees with the proposed BACT control technology of using exclusively natural gas and good combustion practices.

The BACT selection for the fuel gas heaters is summarized below in Table 4-12:

Table 4-12: VOC BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Natural Gas and Good Combustion Practices	Exclusive use of natural gas	N/A	Biennial tune-up for CO

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – 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)

The Plant 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, Table D-30 of the application, 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.[58] 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– Heaters (Step 5)

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

Vendor information indicates that PM emissions from the proposed fuel gas heaters will be less than 0.005 lb/MMBtu. However, instead of a numerical BACT limit, the Plant is proposing exclusive use of natural gas as BACT.

EPD Review – Heaters PM Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM BACT analysis using the resources and information as discussed in the NO_X BACT review.

Conclusion – Heaters PM Control

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

[58] 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).

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

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

The limits for other facilities evaluated above are similar to those reviewed by the Plant. The Division agrees with the proposed BACT control technology of using exclusively natural gas and good combustion practices.

The BACT selection for the fuel gas heaters is summarized below in Table 4-13:

Table 4-13: PM BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM	Natural Gas and Good Combustion Practices	Exclusive use of natural gas	N/A	Fuel records

Fuel Gas Heaters (Source Codes WBH1 and WBH2) – 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 CO_2, CH_4, and N_2O.

Identification of GHG Control Technologies – Heaters (Step 1)

Based on the RBLC search results provided in Appendix D, Table D-31 of the application, 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 CO_2 in larger amounts, or for industrial facilities with high-purity CO_2 steams, consistent with past EPA guidance.[59] 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.

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

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 – Heaters (Step 5)

Based on the Plant review, GHG BACT for the proposed fuel gas heaters should be based on the exclusive use of natural gas as fuel and good combustion practices. The Plant is proposing the exclusive use of natural gas and performing biennial tune-ups required by the Industrial Boiler MACT (40 CFR Part 63, Subpart DDDDD) as GHG BACT.

EPD Review – Heaters GHG Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the GHG BACT analysis using the resources and information as discussed in the NO_X BACT review.

Conclusion – Heaters GHG Control

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

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

The BACT selection for the fuel gas heaters is summarized below in Table 4-14:

Table 4-14: GHG BACT Summary – Heaters (Source Codes WBH1 and WBH2)

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
GHG	Natural Gas and Good Combustion Practices	Exclusive use of natural gas	N/A	Fuel records

Distillate Oil Storage Tank – BACT Review

Distillate Oil Storage Tank – VOC Emissions

Applicant's Proposal

VOC Formation

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

Identification of VOC Control Technologies – Tank (Step 1)

The Plant searched 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, Table D-32 of the application, no add-on control options were identified. Many facilities listed work practice standards such as submerged filling and tank design, including the specific external surface color of the tank, as BACT for VOC emissions. Submerged filling reduces working losses from liquid storage tanks by eliminating splashing and reducing vapor displacement in the tank headspace. The use of light or reflective tank surface colors decreases breathing losses by reducing tank inventory temperature changes caused by solar energy absorptance through the tank shell. Partially or fully insulating the tank roof and/or shell is another method that may be used to decrease breathing losses by reducing the average daily vapor pressure and temperature ranges of the liquid stored.

On October 15, 2024, EPA finalized NSPS Subpart Kc, which applies to certain volatile organic liquid storage vessels, including petroleum liquid storage vessels.[60] Similar to the previous version of the standard, Subpart Kb, EPA requires equipping tanks storing certain liquids with either a floating roof (internal or external) or a closed vent system routed to a control device (such as an adsorption system, flare, or vapor recovery unit). However, this standard does not apply to the proposed diesel storage tank because the vapor pressure of stored liquid (distillate oil) is so low. The Plant has nonetheless evaluated technical feasibility and other factors for these control options, along with use of submerged filling and tank design.

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

The use of submerged filling and light or reflective tank surface colors are inherent to the Project and technically feasible. These are the top control options which are being proposed as BACT for

[60] 89 Fed. Reg. 83296 (October 14, 2024).

VOC emissions from the proposed distillate oil storage tank. Therefore, no further evaluation of the control options is required.[61]

The Plant could not identify a case where the remaining control options noted in Step 1 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.[62] Therefore, use of submerged filling and light or reflective tank surface colors and partially or fully insulating the tank roof are the only technically feasible control options.

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

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

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

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

Selection of Emission Limits for VOC BACT – Tank (Step 5)

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

EPD Review/Conclusion – Distillate Oil Storage Tank VOC Control

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

[61] While 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. at 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.

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

The BACT selection for the storage tank is summarized below in Table 4-15:

Table 4-15: VOC BACT Summary – Distillate Oil Storage Tank

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Submerged filling and use of light-colored/reflective paint on roof/shell	Tank design	N/A	Tank design

Emergency Generators and Fire Water Pump Engine – BACT Review

Emergency Generators and Fire Water Pump Engine Background

Equipment associated with the Project include:

- Up to two (2) ULSD-fired emergency generators rated at 2,000 kW each
- One (1) 350 hp ULSD-fired fire water pump engine
- One (1) 500 kW ULSD-fired emergency generator associated with a support building

Each emergency generator will be compression ignition, certified to Tier 2 emissions standards, and be operated no more 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. The fire water pump engine will also be compression ignition, certified to Tier 3 emission standards, and be operated for less than 500 hours per year, including up to 100 hours per year for maintenance and readiness testing, 50 hours of which may be used in non-emergency situations. All emergency generators and the fire water pump engine will exclusively use ultra-low sulfur diesel (ULSD) as fuel.

In 1994, EPA began regulating emissions of NO_X, PM, CO, and nonmethane hydrocarbons (NMHC) from nonroad engines through a phased approach and has since issued multiple tiers of emission standards for various categories of engines. For new and in-use nonroad compression ignition (CI) engines, EPA issued four tiers of emission standards: Tiers 1, 2, 3, and 4. Once EPA sets emission standards for an engine category, manufacturers must produce engines that meet those standards within the timeframe of the corresponding implementation schedule. The original Tier 1, 2, and 3 standards were adopted in 40 CFR Part 89. EPA has since migrated regulatory requirements for these engines to 40 CFR part 1039 along with the Tier 4 standards.
Stationary engines are generally built to the same specifications as nonroad engines and are subject to the same tiered emission standards through NSPS Subpart IIII. To meet these standards, manufactures employ one of two types of emission control strategies: engine-based technologies and aftertreatment-based technologies. Engine-based technologies include inlet air cooling, fuel injection rate controls, injection timing retard, exhaust gas recirculation, control of air/fuel ratio, and control of air consumption. Collectively, these technologies are referred to as engine design, combustion controls, and good combustion practices, and are the basis for current Tier 2 and Tier 3 engine standards. Aftertreatment-based technologies include the use of SCR and catalyzed diesel particulate filters (CDPF) and are the basis for the current Tier 4 standards. EPA begin 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 generators must be certified to Tier 2 standards, while the fire water pump engine must be certified to Tier 3 standards.[63] 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 the 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.

Emergency Generators and Fire Water Pump Engine – NO_X Emissions

Applicant's Proposal

NO_X Formation

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, Table D-33 of the application, there are several cases in which Tier 4 was listed as BACT for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

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

Purchasing a Tier 2 emergency generator and a Tier 3 fire water pump engine is inherent to the Project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.[64] Therefore, Tier 4 is also considered technically feasible.

[63] See 40 CFR 60.4202(b)(2) for emergency generators (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 water pump engine.

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

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.[65] 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 and 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 generators and fire water pump engine based on the unreasonable estimated annual cost of control.

Selection of Emission Limits for NO_X BACT – Engines (Step 5)

NO_X BACT for the proposed emergency generators and fire water pump engine is based on compliance with NSPS Subpart IIII. The Plant will purchase emergency generators certified to Tier 2 standards and fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions.

EPD Review – Emergency Generators and Fire Water Pump Engine 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 using the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse.[66]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.

The same resources have been utilized in preparing the Division's SO_2, CO, VOC, PM, and GHG BACT analyses.

Conclusion – Emergency Generators and Fire Water Pump Engine NO_X Control

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

[65] 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.

[66] https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en

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

- Cronus Chemicals, 3,985 hp, 6.4 g/kwh (4.8 g/hp-hr): 360 hp, 4 g/kw-hr (3 g/bhp)
- Nucor Steel Arkansas, 3,634 hp, 5.6 g/kw-hr
- Midwest Fertilizer Company, 3,600 hp, 4.42 g/hp-hr
- Nucor Steel, 3,000 hp, 4.8 g/hp-hr
- Sycamore Riverside Energy LLC, 2,011 hp, 4.56 g/hp-hr
- Shintech Louisiana, LLC, 552 hp, 4 g/kw-hr
- Lincoln Land Energy Center, 320 hp, 4 g/kw-hr
- MEC North. LLC and MEC South LLC, 300 hp, 3 g/bhp

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

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

The BACT selection for the emergency generators and fire water pump engine is summarized below in Table 4-16:

Table 4-16: BACT Summary – Emergency Generators and Fire Water Pump Engine

Emission Unit	Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Emergency Generators	NO_X, SO_2, CO, VOC, PM	Tier 2 Engine Ultra-low sulfur diesel	NSPS Subpart IIII Standards	N/A	Compliance with NSPS Subpart IIII
	GHG	Ultra-low sulfur diesel	NSPS Subpart IIII Standards	N/A	Compliance with NSPS Subpart IIII
Fire Water Pump Engine	NO_X, SO_2, CO, VOC, PM	Tier 3 Engine Ultra-low sulfur diesel	NSPS Subpart IIII Standards	N/A	Compliance with NSPS Subpart IIII
	GHG	Ultra-low sulfur diesel	NSPS Subpart IIII Standards	N/A	Compliance with NSPS Subpart IIII

Emergency Generators and Fire Water Pump Engine – SO_2 Emissions

Applicant's Proposal

SO_2 Formation – Engines

Emissions of SO_2 occur as a result of the oxidation of sulfur-containing compounds in the fuel during the combustion process. SO_2 emissions associated with combustion of ultra-low sulfur diesel (ULSD) are very low due to the low concentration of sulfur compounds in the fuel.

Identification of SO_2 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 IIII. Please refer to 40 CFR 60.4207 and 1090.305. Because of this, 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 of the application. The use of ULSD has consistently been determined to be SO_2 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 SO_2 Control Options – Engines (Step 2)

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

Summary and Ranking of Remaining SO_2 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 SO_2 emissions from the proposed emergency generators and fire water pump engine.

Evaluation of Most Stringent SO_2 Controls – Engines (Step 4)

The top control option is being proposed for SO_2 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 SO_2 BACT – Engines (Step 5)

Based on the Plant review, SO_2 BACT for the proposed emergency generators and fire water pump should be based on the use of fuels with inherently low sulfur content. Therefore, the Plant proposes the use of ultra-low sulfur diesel in compliance with NSPS Subpart IIII as SO_2 BACT for the proposed engines.

EPD Review and Conclusion – Emergency Generators and Fire Water Pump SO_2 Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO_2 BACT analysis using resources and information as discussed in the NO_X BACT review. The Division agrees that the exclusive use of ultra-low sulfur diesel represents BACT control technology for SO_2. The Division also agrees with the Plant's proposed use of ULSD in compliance with NSPS Subpart IIII as BACT for the emergency generators and fire water pump engine.

The BACT selection for the emergency generators and fire water pump engine is summarized above in Table 4-16.

Emergency Generators and Fire Water Pump Engine – CO Emissions

Applicant's Proposal

CO Formation - Engines

CO emissions from the proposed emergency generators 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 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 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.[67]

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 – Engines (Step 5)

CO BACT for the proposed emergency generator and fire water pump engine is based on compliance with NSPS Subpart IIII. The Plant will purchase emergency generators certified to

[67] 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.

Tier 2 standards and fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions.

EPD Review – Emergency Generators and Fire Water Pump Engine CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis using the same resources as discussed in the NO_X BACT analysis.

Conclusion – Emergency Generators and Fire Water Pump Engine CO Control

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

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

- LBLW Erickson Station, 6,000 hp, 3.5 g/kw-hr
- Cronus Chemicals, 3,985 hp, 3.5 g/kwh (2.6 g/hp-hr): 369 hp, 3.5 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- Sycamore Riverside Energy LLC, 2,011 hp, 2.6 g/hp-hr
- Shintech Louisiana, LLC, 552 hp, 4 g/kw-hr
- Belle River Combined Cycle Plant, 399 hp, 3.5 g/kw-hr
- Lincoln Land Energy Center, 320 hp, 3.5 g/kw-hr
- MEC North. LLC and MEC South LLC, 300 hp, 2.6 g/bhp

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

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

The BACT selection for the emergency generators and fire water pump engine is summarized above in Table 4-16.

Emergency Generators and Fire Water Pump Engine – VOC Emissions

Applicant's Proposal

VOC Formation – Engines

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

Identification of VOC Control Technologies – Engines (Step 1)

As discussed above, available control options for VOC (NMHC) emissions from the proposed emergency generators and fire water pump 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, Table D-36 of the application, 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 generators 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.[68] 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 and fire water pump engine, which will be operated for a maximum of 500 hours per year. Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and fire water pump engine based on the unreasonable estimated annual cost of control.

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

Selection of Emission Limits for VOC BACT – Engines (Step 5)

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

EPD Review – Emergency Generators and Fire Water Pump Engine VOC Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the VOC BACT analysis using the same resources as discussed in the NO_X BACT analysis.

Conclusion – Emergency Generators and Fire Water Pump Engine VOC Control

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

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

- Cronus Chemicals, 3,985 hp, 6.4 g/kwh (4.8 g/hp-hr): 369 hp, 4 g/kw-hr
- Nucor Steel Arkansas, 3,634 hp, 3.5 g/kw-hr
- Magnolia Power Generating Station, 2,937 hp, 4.8 g/hp-hr
- Riverview Energy Corporation, 2,800 hp, 6.4 g/kw-hr
- Shintech Louisiana, LLC, 552 hp, 4 g/kw-hr

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

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

The BACT selection for the emergency generators and fire water pump engine is summarized above in Table 4-16.

Emergency Generators and Fire Water Pump Engine – PM Emissions

Applicant's Proposal

PM Formation – Engines

PM emissions from the proposed emergency generators 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 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, Table D-37 of the application, there were no cases in which Tier 4 was identified as BACT for PM. However, the Plant has evaluated technical feasibility and other factors for this control option.

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

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

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

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

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

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for PM to be between ~$160,000 and $970,000 per ton when applied to emergency engines with similar power ratings.[69] 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 and fire water pump engine, which will be operated for a maximum of 500 hours per year. Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and fire water pump engine based on the unreasonable estimated annual cost of control.

[69] 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.

Selection of Emission Limits for PM BACT – Engines (Step 5)

PM BACT for the proposed emergency generators and fire water pump engine is based on compliance with NSPS Subpart IIII. The Plant will purchase emergency generators certified to Tier 2 standards and fire water pump engine certified to Tier 3 standards and operate and maintain each according to manufacturer's emission-related instructions

EPD Review – Emergency Generators and Fire Water Pump Engine PM Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM BACT analysis using the same resources as discussed in the NO_X BACT analysis.

Conclusion – Emergency Generators and Fire Water Pump Engine PM Control

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

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

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

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

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

The BACT selection for the emergency generators and fire water pump engine is summarized above in Table 4-16.

Emergency Generators and Fire Water Pump Engine – GHG Emissions

Applicant's Proposal

GHG Formation – Engines

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

Identification of GHG Control Technologies – Engines (Step 1)

While some engine-based technologies may promote fuel efficiency, EPA's tiered emission standards for CI ICE do not address GHG emissions directly. Based on the RBLC search results provided in Appendix D, Table D-38 of the application, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generators 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 include 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, this option will not be considered further in this analysis, as it would interfere with the intended function of the units.

Additionally, CCS should not be considered as a potentially available control option since GHG emissions from the proposed emergency generator and fire water pump engine are insignificant. CCS should only be considered as an available control option for facilities that emit CO2 in larger amounts, or for industrial facilities with high-purity CO_2 steams, consistent with past EPA guidance.[70] Accordingly, use of ULSD, good combustion practices, and limiting annual operating hours are the only potentially available control options for GHG emissions from the proposed emergency generators and fire water pump 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 generators and fire water pump engines.

[70] 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 generators and fire water pump engines. Therefore, no evaluation of the control options is required.

Selection of Emission Limits for GHG BACT – Engines (Step 5)

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

EPD Review – Engines GHG Control

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period. The Division agrees that clean fuels, efficient design, and good combustion, operating, and maintenance practices represents BACT control technology for greenhouse gases (GHG).

Conclusion – Engines GHG Control

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

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

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

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

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

The BACT selection for the emergency generators and fire water pump engine is summarized below in Table 4-17.

Table 4-17: BACT Summary – Emergency Generators and Fire Water Pump Engine – GHG Control

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

Applicant's Proposal – Summary of Proposed BACT

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

Table 4.18: Proposed BACT Emission Limits and Compliance Demonstration Methods.

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
Combined-Cycle Units	NO_X	Natural Gas	DLN Combustors, Water Injection, & Selective Catalytic Reduction	2.0 ppmvd NO_X, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Distillate Oil		5.0 ppmvd NO_X, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 4-hour rolling average
		Both		205.8 tons NO_X or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-month rolling average
	CO	Natural Gas	Good Combustion Practices & Oxidation Catalyst	2.0 ppmvd CO, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 24-hour rolling average
		Distillate Oil		2.0 ppmvd CO, corrected to 15% O_2, excluding periods of startup, shutdown, and fuel switching	CEMS, 24-hour rolling average
		Both		258.4 tons CO or less during any 12-month consecutive period, including periods of startup, shutdown, and fuel switching	CEMS, 12-month rolling average
	VOC	Natural Gas	Good Combustion Practices & 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	
	PM	Natural Gas	Low Sulfur Content Fuels	0.0044 lb/MMBtu	3-run stack test EPA reference Method 5 and 202
		Distillate Oil		0.0135 lb/MMBtu	
	SO_2 and H_2SO_4	Natural Gas	Low Sulfur Content Fuels	Natural gas, 0.5 grains sulfur /100 scf Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel supplier documentation
		Distillate Oil			
	GHG	Both	Clean/Low Emitting Fuels, Efficient Design, & Good Combustion, Operating, and	900 lb CO_2e/MWh-gross	CEMS, 12-month rolling average

Emission Unit	Pollutant	Fuel	Selected BACT	Emissions/Operation Limit	Compliance Method
			Maintenance Practices		
Emergency Generators	NO_X, SO_2, CO, VOC, PM	Distillate Oil	NSPS Subpart IIII Standards	Tier 2 Engine Ultra-low sulfur diesel	Compliance with NSPS Subpart IIII
	GHG	Distillate Oil	Clean/Low Emitting Fuels	Ultra-low sulfur diesel	Compliance with NSPS Subpart IIII
Fire Water Pump Engine	NO_X, SO_2, CO, VOC, PM	Distillate Oil	NSPS Subpart IIII Standards	Tier 3 Engine Ultra-low sulfur diesel	Compliance with NSPS Subpart IIII
	GHG	Distillate Oil	Clean/Low Emitting Fuels	Ultra-low sulfur diesel	Compliance with NSPS Subpart IIII
Fuel Oil Storage Tank	VOC	Distillate Oil	Submerged filling & use of light-colored/reflective paint on roof/shell	Tank design	Tank design
Fuel Gas Heaters	NO_X	Natural Gas	Ultra-low NO_X Burners & Good Combustion Practices	9 ppmvd, corrected to 3% O_2, or 0.11 lb/MMBtu	Biennial tune-up
	CO	Natural Gas	Good Combustion Practices	100 ppmvd, corrected to 3% O_2, or 0.074 lb/MMBtu	Biennial tune-up
	VOC	Natural Gas	Good Combustion Practices	Exclusive use of natural gas	Biennial tune-up for CO
	PM	Natural Gas	Low Sulfur Content Fuel	Exclusive use of natural gas	Fuels records
	SO_2	Natural Gas	Low Sulfur Content Fuel	Exclusive use of natural gas	Fuels records
	GHG	Natural Gas	Clean/Low Emitting Fuels	Exclusive use of natural gas	Fuels records

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Combined Cycle Units (Source Codes CT12/DB12 and CT13/DB13)
Initial performance tests are required on the CC units for NO_X to demonstrate compliance with the emission standards set forth in NSPS Subpart KKKKa, in accordance with procedures specified in paragraph (b) of 40 CFR 60.4405a. Compliance with these emissions standards will be verified based on CEMS data.

Initial performance tests are also required on the CC units for PM and VOC to show compliance with the PSD limits. The test for VOC is required to be repeated every five years.

Subpart KKKKa also requires SO_2 testing for the CC units using fuel monitoring and the procedures specified in 40 CFR 60.4415a. These requirements are incorporated in the record keeping and reporting section of the permit.

Fuel Gas (Water Bath) Heaters (Source Codes WBH1 and WBH2)
Initial and biennial tune-ups are required on the fuel gas heaters for NO_X and CO to show compliance with the PSD limits.

Monitoring Requirements:

Combined Cycle Units (Source Codes CT12/DB12 and CT13/DB13)
NO_X and CO CEMS are required on the combined cycle combustion turbines. The NO_X CEMS is required to comply with Performance Specification 2 or 3 (Appendix B), Procedure 1 (Appendix F), and/or 40 CFR Part 75. The CO CEMS is required to comply with Procedure 1 (Appendix F). Minimum data requirements are also included.

The procedures to determine compliance with the various NO_X limits (PSD and NSPS Subpart KKKKa), PM, VOC, CO, SO_2, H_2SO_4, and GHG limits (PSD) are included in the permit.

Monitoring the natural gas usage in each of the CC units is required, and the sulfur content of natural gas is monitored per NSPS Subpart KKKKa requirements.

Fire Pump Engine and Emergency Generators
A non-resettable hour meter is required on the fire pump engine and the emergency generators to track compliance with the hours of operation limits. The procedures to determine compliance with the 12-month hours of operation limits are included in the permit.

CAM Applicability:

The proposed CC units (Source Codes CT12/DB12 and CT13/DB13) 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 proposed CC units are subject to CAM for the proposed NO_X, CO, and VOC BACT limits. NSPS Subpart KKKKa requires the proposed CC units to be equipped with a NO_X CEMS in order to monitor compliance. The Plant is proposing to utilize the NO_X CEMS as a CAM indicator to provide reasonable assurance of continuous compliance with the proposed NO_X BACT limit.

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

Detailed CAM requirements are provided in Appendix E of the application.

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 NO_2, CO, $PM_{2.5}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, PM_{10}, and $PM_{2.5}$.

The proposed project at the Plant triggers PSD review for PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, CO, GHG in terms of carbon CO_2e, and H_2SO_4. An air quality analysis was conducted to demonstrate the Plant's compliance with the NAAQS and PSD Increment standards for PM_{10}, $PM_{2.5}$, CO, NO_2, and SO_2. 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, PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, and CO that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. VOC does not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Chatham County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_X limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, and CO emissions increases at the Plant would significantly impact the area surrounding the Plant. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

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

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

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

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

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the Plant with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. According to EPA guidance, permitting authorities may use a SIL for $PM_{2.5}$, so long as it is justified, of 1.2 μg/m^3 for the 24-hour standard and 0.13 μg/m^3 for the annual standard.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	Significant Impact Level (ppm or μg/m^3)	Monitoring Deminimis Concentration (μg/m^3)
Ozone	8-hour	0.001 (ppm)	--
PM_{10}	Annual	1	--
	24-Hour	5	10
$PM_{2.5}$	Annual	0.13	--
	24-Hour	1.2	--
SO_2	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
NO_X	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

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

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

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
Ozone	8-Hour	--	0.070
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_X	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 Plant McIntosh, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate whether the project will cause or contribute to an exceedance.

PSD Increment Analysis

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

U.S. EPA has established PSD Increments for NO_X, SO_2, PM_{10}, and $PM_{2.5}$; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. Plant McIntosh 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

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
	24-Hour	5	91
	3-Hour	25	512
NO_X	Annual	2.5	25

To demonstrate a project will not cause or contribute to an exceedance of the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the Plant and those sources in the regional inventory would be modeled and compared 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 dates are February 8, 1988 for NO_X, January 6, 1975 for SO_2 and PM_{10}, and October 20, 2011 for $PM_{2.5}$. 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 NO_2 as May 5, 1988, for PM_{10} and SO_2 as October 30, 1979, and for $PM_{2.5}$ as October 20, 2011.

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 of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not result in ambient impacts of ozone, SO_2, PM_{10}, or CO above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further refined modeling 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	Maximum Impact[1] (ug/m^3)	SIL (ug/m^3)	Significant?
Ozone	8-hour	**0.002479**	0.001	**Yes**
CO	1-hour	476.06326	2,000	No
	8-hour	107.67609[&]	500	No
NO_2	1-hour	**9.917020**[^]	7.5	**Yes**
	Annual	0.392150[^]	1	No

Pollutant	Averaging Period	Maximum Impact[1] (ug/m^3)	SIL (ug/m^3)	Significant?
SO_2	1-hour	1.215810	7.8	No
	3-hour	1.123780	25	No
	24-hour	0.406050	5	No
PM_{10}	24-hour	2.010860	5	No
	Annual	0.105110	1	No
$PM_{2.5}$	24-hour	**1.962140**	1.2	**Yes**
	Annual	0.101140	0.13	No

Data for worst year provided only.
* The applicant did not include emergency equipment in modeling runs for short-term averaging periods (e.g., 1-hour, 3-hour, 8-hour, and 24-hour). 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 SO_2 emissions at the proposed Plant.
& 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.
^ Results differ from the load analysis because NO_2 SIL modeling was run with the ARM2 configuration while the load analysis assuming a flat 90% NO_x to NO_2 conversion rate that is higher than the conversion rate used by ARM2.

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for ozone, SO_2, PM_{10}, and CO. However, maximum modeled impacts were above the SILs for NO_X and $PM_{2.5}$. Therefore, a Cumulative Impact Analysis was conducted for ozone, NO_X and $PM_{2.5}$ for the 8-hour, 1-hour, and 24-hour averaging periods, respectively.

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 Plant 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 Plant and the furthest receptor from the Plant that showed a modeled concentration exceeding the corresponding SIL was determined to be less than 6.0 kilometers for 1-hr NO_2 and 1.5 km for 24-hr $PM_{2.5}$. To be conservative, regional source inventories for both of these pollutants were prepared for sources located within 2.0 kilometers of the Plant.

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 Plant's SIA are ideally included in this regional inventory. Plant McIntosh 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.

Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire Plant's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the Plant 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 Plant's SIA due to the potential emissions from all sources at the Plant 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 comparison with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, the analysis demonstrates that the project will not cause or contribute to an exceedance of the NAAQS.

Table 6-5: NAAQS Analysis Results*

Pollutant	Averaging Period	Max Modeled Conc. (μg/m^3)#	Background (μg/m^3)	Secondary Impact (μg/m^3)		Total (μg/m^3)	NAAQS (μg/m^3)	Exceeds NAAQS?
				Project$	Offsite&			
Ozone	8-hour	0.002479	0.059	N/A	N/A	0.061	0.070	No
NO_2	1-hour	97.166070	30.3	N/A	N/A	127.4660	188.7	No
$PM_{2.5}$	24-hour	5.272460	19	0.044330	2.620182	26.9369	35	No

Data for worst year provided only.

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods (e.g., 1-hour, 3-hour, 8-hour, and 24-hour). 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 SO_2 emissions at the proposed Plant.

& Secondary $PM_{2.5}$ impacts were estimated with the MERP approach using the NO_X and SO_2 emissions at inventory sites included in the modeling analysis.

As indicated in Table 6-5 above, the total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

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

Table 6-6: Increment Analysis Results*

Pollutant	Averaging Period	Max Modeled Conc. ($\mu g/m^3$)#	Secondary Project Impact ($\mu g/m^3$)$	Total ($\mu g/m^3$)&	Class II PSD Increment ($\mu g/m^3$)	Exceed Increment?
$PM_{2.5}$	24-hour	3.077300	0.044330	3.121630	9	No

Data for worst year provided only

* The applicant did not include emergency equipment in modeling runs for short-term averaging periods (e.g., 1-hour, 3-hour, 8-hour, and 24-hour). 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 SO_2 emissions at the proposed Plant.

& 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 NO_x and SO_2 emissions have decreased and therefore increment expansion has occurred since the original $PM_{2.5}$ baseline dates were set.

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

Ambient Monitoring Requirements

Class I Area Analysis

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

The three Class I areas within approximately 200 kilometers of the McIntosh Combined-Cycle Facility are the Wolf Island Wilderness, located approximately 108 kilometers south of the Plant; the Cape Romain Wilderness, located approximately 156 kilometers northeast of the Plant; and the Okefenokee Wilderness, located approximately 174 kilometers southwest of the Plant. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of all three of these Class I areas.

No adverse comments were received from the applicable FLMs. The applicant's initial Q/d analysis for distillate oil related to the Wolf Island Class I area yielded a value above 10. The applicant provided additional information demonstrating that sulfur was double counted in estimated H_2SO_4 and SO_2 emissions and that, if this conservatism were to be removed, the resulting Q/d value would be below 10. The FLM response indicates that FLMs will not request an additional Class I AQRV analysis at this time but wish to be updated if project emissions end up exceeding initial estimations.

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 Plant and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

As required, an analysis of the Plant's potential impact on soils and vegetation in the vicinity of the Project was performed by comparing maximum modeled concentrations from the SIL analysis with secondary NAAQS. Secondary NAAQS define maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS have been adopted for NO_2, PM_{10}, $PM_{2.5}$, and SO_2.

The highest modeled concentrations of NO_2, PM_{10}, $PM_{2.5}$, and SO_2 from the Project were compared to each secondary NAAQS as shown in Table 7-3 of the modeling memo in Attachment C of this document. The modeled concentrations are all well below each applicable secondary NAAQS; therefore, no significant impacts on local soils and vegetation are expected as a result of the Project.

Growth

A qualitative evaluation of the general commercial, residential, industrial, and other growth associated with the Project was conducted. Negligible growth is expected to be associated with the Project, which only involves construction of new CC units and associated ancillary equipment and infrastructure. Therefore, no analysis of secondary impacts from associated grown was 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. Savannah National Wildlife Refuge is the only site 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 Plant may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

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

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

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

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

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

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

A Level II analysis refines selected Level I input parameters by using representative wind speed and atmospheric stability conditions in the region encompassing both emission source and the sensitive receptor. In contrast, the Level I analysis assumed worst-case parameters (Pasquill-Gifford stability class F and wind speed of 1.0 meters per second) that are not necessarily indicative of local weather patterns that affect visibility when winds blow emission from the Plant toward each of these sensitive receptors. A summary of VISCREEN Level II results is shown in the table below. A detailed analysis may be found in Attachment C of this document.

Table 7-1: VISCREEN Results inside Savannah National Wildlife Refuge

Background	Theta[1]	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	155	5.3	14	2.00	1.405	0.05	0.022
SKY	140	155	5.3	14	2.00	1.622	0.05	-0.040[2]
TERRAIN	10	84	3.0	84	2.00	10.293	0.05	0.042
TERRAIN	140	84	3.0	84	2.00	1.64	0.05	0.019

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

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, except for the terrain viewing background. Given that there are no elevated scenic vistas with terrain as background for this area, the proposed modifications to the Plant are not anticipated to cause adverse impacts on visibility at the sensitive receptors in the area surrounding the Project.

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 Plant 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 Plant-wide emissions of any TAP emitted by a Plant. To conduct a Plant-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the Plant is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the natural gas and distillate oil fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

Table 7-2: Comparison of Site-Wide TAP Emissions to MERs

Pollutants	Annual Emissions (lb/yr)	MER (lb/yr)	Exceeds MER?	AAC Analysis Required?
Arsenic	1.11E+03	5.67E-02	**Y**	**Y**
Beryllium	3.23E+01	9.73E-01	**Y**	**Y**
Cadmium	6.50E+02	1.35E+00	**Y**	**Y**
Chromium	1.31E+03	5.84E+01	**Y**	**Y**
Cobalt	2.31E+01	1.17E+01	**Y**	**Y**
Lead	1.45E+03	5.84E+00	**Y**	**Y**
Manganese	7.74E+04	1.22E+01	**Y**	**Y**
Mercury	1.60E+02	7.30E+01	**Y**	**Y**
Nickel	7.95E+02	3.86E+01	**Y**	**Y**
Selenium	2.45E+04	2.34E+01	**Y**	**Y**
Acetaldehyde	1.12E+04	1.11E+03	**Y**	**Y**
Acrolein	1.79E+03	8.51E+01	**Y**	**Y**
Ammonia	1.32E+06	2.43E+04	**Y**	**Y**
Benzene	7.40E+03	3.16E+01	**Y**	**Y**
1,3-Butadiene	1.64E+03	7.30E+00	**Y**	**Y**
1,1,1-Trichlorobenzene	1.63E+02	2.20E+05	N	N
Dichlorobenzene	2.81E-01	1.74E+04	N	N
Ethylbenzene	8.94E+03	2.43E+05	N	N
Formaldehyde	1.13E+05	2.21E+01	**Y**	**Y**
Hexane	4.21E+02	1.70E+05	N	N
Propylene Oxide	8.10E+03	6.57E+02	**Y**	**Y**
Sulfuric Acid	2.30E+05	1.17E+02	**Y**	**Y**
Toluene	3.63E+04	1.22E+06	N	N
Xylenes	1.79E+04	2.43E+04	N	N
Acenaphthene	9.80E-02	N/A	N	N
Acenaphthylene	1.95E-01	N/A	N	N
Anthracene	2.78E-02	N/A	N	N
Benz(a)anthracene	1.49E-02	N/A	N	N
Benzo(a)pyrene	5.75E-03	N/A	N	N
Benzo(b)flouranthene	2.33E-02	N/A	N	N
Benzo(g,h,I)perylene	1.22E-02	N/A	N	N
Benzo(k)fluoranthene	5.06E-03	N/A	N	N
Chrysene	3.22E-02	N/A	N	N
Dibenzo(a,h)anthracene	7.99E-03	N/A	N	N
Dimethylbenz(a)Anthracene, 7,12-	3.74E-03	N/A	N	N
Fluoranthene	9.14E-02	N/A	N	N
Fluorene	2.94E-01	N/A	N	N
Indeno(1,2,3-cd)pyrene	9.31E-03	N/A	N	N
Methylnaphthalene, 2-	5.62E-03	N/A	N	N
Methylcholanthrene, 3-	4.21E-04	N/A	N	N
Naphthalene	3.64E+03	7.30E+02	**Y**	**Y**
Phenanathrene	8.73E-01	N/A	N	N
Pyrene	8.23E-02	N/A	N	N
Total POM	9.25E+02	N/A	N	N

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

Determination of Toxic Air Pollutant Impact

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

Initial Screening Analysis Technique

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

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

Table 7-3: TAP MGLC Assessment

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)	Above AAC?
Acetaldehyde	15-min	4,500	0.155608	No
	Annual	4.55	0.002015	No
Acrolein	15-min	23	0.024840	No
	Annual	0.35	0.000321	No
Ammonia	15-min	2,400	22.920968	No
	Annual	100	0.343657	No
Arsenic	15-min	0.2	0.016035	No
	Annual	0.000233	0.000112	No
Benzene	15-min	1,600	0.116940	No
	Annual	0.13	0.000794	No
Beryllium	15-min	0.5	0.000461	No
	Annual	0.004	0.000003	No
1,3-Butadiene	15-min	1,100	0.023324	No
	Annual	0.03	0.000164	No
Cadmium	15-min	30	0.008623	No
	Annual	0.00556	0.000072	No
Chromium (III)	24-hour	1.2	0.001616	No
Chromium (VI)	15-min	10	0.002915	No
	Annual	0.0000555	0.000020	No
Cobalt	24-hour	0.24	0.000057	No

Formaldehyde	15-min	245	1.283439	No
	Annual	0.0909	0.013558	No
Lead	24-hour	0.12	0.002311	No
Manganese	15-min	500	1.129816	No
	Annual	0.05	0.007680	No
Mercury	15-min	10	0.002132	No
	Annual	0.3	0.000018	No
Naphthalene	15-min	7,500	0.053211	No
	Annual	3	0.000369	No
Nickel	24-hour	0.794	0.001459	No
Propylene Oxide	Annual	2.7	0.001451	No
Selenium	24-hour	0.48	0.040069	No
Sulfuric Acid	15-min	300	3.777840	No
	24-hour	2.4	0.573961	No

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed Plant are included in draft Permit Amendment No. 4911-103-0014-V-06-3.

Section 1.0: Facility Description

"The Plant" applied for a permit to construct up to two (2) combined-cycle (CC) electric generating units, arranged in a 1-on-1 configuration, each of which includes an advanced-class dual-fuel combustion turbine (CT) generator, heat recovery steam generator (HRSG) with natural gas-fired duct burner, and steam turbine (ST) generator at Plant McIntosh ("the Plant"), located in Effingham County, Georgia. Each CT will be capable of firing either pipeline quality natural gas or distillate oil. The proposed project will construct the proposed CC units and will include installation of new associated equipment, such as the two (2) fuel gas heaters (Source Codes WBH1 and WBH2), three (3) emergency generators, one (1) fire water pump engine, two (2) cooling towers, and one (1) distillate oil storage tank.

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

Table 3.1.1 was updated to include the following proposed equipment for the Project: combustion turbines CT12 and CT13; HRSGs and duct burners DB12 and DB13; and the fuel gas (water bath) heaters WBH1 and WBH2. The cooling towers, emergency generators, fire water pump engine, and distillate oil tank were added to the Insignificant Activities Checklist in Attachment B of the permit.

New Condition 3.2.1 contains a limit for total distillate oil fired in each of the new combustion turbines (Source Codes: CT12 and CT13) during any 12 consecutive months.

Condition 3.3.1 clarifies that each combustion turbine and duct burner share a common stack. The condition was modified to include the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

Condition 3.3.2 restricts fuel fired in the combustion turbines to only pipeline quality natural gas or ultra-low sulfur diesel fuel. It was modified to correct "diesel fuel" to "distillate oil" and to include the new units (Source Codes: CT12 and CT13).

Condition 3.3.3 restricts fuel fired in the duct burners to only pipeline quality natural gas. It was modified to include the new duct burners (Source Codes: DB12 and DB13).

Condition 3.3.4 contains a sulfur limit for diesel fuel fired in the combustion turbines. It was modified to correct "diesel fuel" to "distillate oil and to include the new units (Source Codes: CT12 and CT13).

Conditions 3.3.5, 3.3.6, 3.3.7, 3.3.8, and 3.3.9 are being deleted since emission limitations throughout the permit require operation of BACT for compliance for the new and existing CC units.

Conditions 3.3.10, 3.3.14, and 3.3.16 contain specific emission limits for the combustion turbines and duct burners listed in Condition 3.3.1. These conditions were revised to clarify that the emission limits apply specifically to the turbines and burners listed in paragraphs a. through d. of Condition 3.3.1.

Condition 3.3.11 contains startup and shut down definitions as used in the permit. It was modified to include definitions for fuel switching and to specify which definitions are applicable to each combustion turbine/duct burner unit. It was also revised to include specifications for turbine tuning, per 40 CFR 60.4420a.

Condition 3.3.15 restricts operating hours for the combustion turbines during any consecutive 12 months when firing ultra-low sulfur diesel fuel. It was modified to correct "diesel fuel" to "distillate oil."

Condition 3.3.17 requires the Plant to comply with all applicable provisions of 40 CFR 63 Subpart YYYY for each of the combustion turbines. The condition was modified to include the new combustion turbines (Source Codes: CT12 and CT13).

Condition 3.3.18 sets forth a formaldehyde concentration limit in accordance with 40 CFR 63 Subpart YYYY requirements for the combustion turbines. The condition was modified to include the new combustion turbines (Source Codes: CT12 and CT13).

Condition 3.3.20 defines "gas fired operation" for the use of natural gas in the combustion turbines per Subpart YYYY requirement. It was modified to include the new combustion turbines (Source Codes: CT12 and CT13).

New Conditions 3.3.22, 3.2.23, and 3.3.24 contain PSD emission limits, emission limits during natural gas combustion, and emission limits during fuel oil combustion for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 3.3.25 requires the Plant to comply with applicable requirements of 40 CFR 60 Subparts A and KKKKa for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 3.3.26 subjects the combustion turbines (Source Codes: CT12 and CT13) to the requirements of 40 CFR 60 Subpart TTTT or TTTTa, as applicable.

New Condition 3.3.27 requires the Plant to comply with applicable requirements of 40 CFR 63 Subparts A and DDDDD for the fuel gas heaters (Source Codes: WBH1 and WBH2).

New Condition 3.3.28 requires the Plant to conduct a biennial tune-up of the fuel gas heaters (Source Codes: WBH1 and WBH2) per 40 CFR 63 Subpart DDDDD requirements.

New Conditions 3.3.29 restricts the fuel fired in the fuel gas heaters (Source Codes: WBH1 and WBH2) to only pipeline quality natural gas.

New Condition 3.3.30 contains PSD emission limits for the fuel gas heaters (Source Codes: WBH1 and WBH2).

New Condition 3.3.31 requires the use of a submerged fill pipe for the distillate oil storage tank.

New Conditions 3.4.1 and 3.4.2 contain Georgia State Rule (d) requirements for the fuel gas heaters (Source Codes: WBH1 and WBH2).

New Condition 3.4.3 contains Georgia State Rule (d) requirements for the combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

Section 4.0: Requirements for Testing

General Test Method Requirements in Condition 4.1.3 were modified to include additional test methods for total particulate matter.

Condition 4.2.1 outlines testing procedures in accordance with 40 CFR 63 Subpart YYYY requirements for the combustion turbines. The condition was modified to include new combustion turbines CT12 and CT13 and to update a test method reference.

New Conditions 4.2.4 through 4.2.6 were added outlining performance test requirements for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

Section 5.0: Requirements for Monitoring

Condition 5.2.1 requires the Plant to install a NO_X CEMS and a CO CEMS for the turbines and duct burners listed Condition 3.3.1. The condition was modified to require the Plant install a system on new combustion turbines/duct burners CT12/DB12 and CT13/DB13 to continuously monitor NO_X, CO, and the hourly gross electric output in accordance with PSD and 40 CFR 60 Subpart TTTT/TTTTa requirements.

Condition 5.2.2 lists specific monitoring parameters for each of the combustion turbines and duct burners. The condition was modified to include the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13) and to correct “diesel fuel” to “distillate oil.”

Condition 5.2.3 contains fuel monitoring requirements for the existing combustion turbines. The condition was modified to correct “diesel fuel” to “distillate oil.”

Condition 5.2.4 sets forth exceptions for using Appendix F, Procedure 1 to conduct quality assurance testing for CEMS monitoring. The condition was revised in accordance with updated procedures.

Condition 5.2.5 contains requirements for collecting CO emissions data from each combustion turbine. It was revised to reference each applicable combined cycle unit and to specify turbine operating days during which CO emissions data should be collected.

Condition 5.2.7 contains requirements for calculating a three-hour average NO_X emission rate for each combined cycle unit. It was modified to correct “diesel fuel” to “distillate oil” and to clarify calculation requirements of the three-hour average.

Condition 5.2.8 contains requirements for calculating a four-hour average NO_X emission rate for each combined cycle unit. It was modified to correct “diesel fuel” to “distillate oil.”

Condition 5.2.10 contains requirements for calculating a three-hour average CO emission rate for each combined cycle unit. It was modified to correct “diesel fuel” to “distillate oil” and to clarify calculation requirements of the three-hour average.

Condition 5.2.11 lists all emission units subject to CAM. The new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13) were added for NO_X, CO, and VOC.

Conditions 5.2.12 and 5.2.13 outline performance criteria for compliance with CAM requirements for NO_X emissions and CO and VOC emissions, respectively. These conditions were modified to include the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13.) Condition 5.2.13 was also modified to specify that CO CEMS is an indicator for VOC emissions for the new units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 5.2.18 contains requirements for biennial tuneups per 40 CFR 63 Subpart DDDDD requirements for the new fuel gas heaters (Source Codes: WBH1 and WBH2).

New Condition 5.2.19 requires the Plant to continuously monitor and record natural gas quantities fired in WBH1 and WBH2.

New Condition 5.2.20 outlines NO_X monitoring requirements during the biennial tuneup required in New Condition 5.2.18.

New Condition 5.2.21 requires the Plant to install a non-resettable hour meter on the emergency fire pump engines and emergency generators (Source Codes: FP1, EG1, EG2, and EG3).

New Conditions 5.2.22 and 5.2.23 require fuel supplier certifications for the pipeline quality natural gas and fuel oil fired in the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 5.2.24 through 5.2.26 state the quality assessment requirements of the NO_X CEMs and the CO CEMs for the combustion turbines (CT12 and CT13).

New Condition 5.2.27 explains the definition of valid operating requirements per NSPS 60 Subparts TTTT or TTTTa.

Section 6.0: Other Recordkeeping and Reporting Requirements

Conditions 6.1.7.a, 6.1.7.b, and 6.1.7.c. were modified to include excess emissions limitations, exceedances, and excursions, respectively, for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13) and fuel gas heaters (Source Codes: WBH1 and WBH2).

Condition 6.1.7.d was modified to include the new combustion turbines (CT12 and CT13) with the semiannual compliance report per 40 CFR 63 Subpart YYYY requirements.

Conditions 6.2.1 through 6.2.4 contain specific recordkeeping requirements for the combined cycle units. These conditions were revised to include the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13) and to correct “diesel fuel” to “distillate oil.”

Condition 6.2.6 contains fuel supplier verification requirements for the combustion turbines. It was revised to include the new combustion turbines (Source Codes: CT12 and CT13) and to correct “diesel fuel” to “distillate oil.”

Conditions 6.2.7 and 6.2.8 contain compliance verification requirements for operational limits for the combustion turbines. These conditions were revised to correct “diesel fuel” to “distillate oil.” Condition 6.2.8 was also revised to specify the combustion turbines referenced.

Condition 6.2.12 outlines requirements for determining CO emissions from each combined cycle unit. Language therein was revised for coherence.

Condition 6.2.15 outlines semiannual reporting requirements. It was revised to correct “diesel fuel” to “distillate oil” and to include requirements for the new combined cycle units (Source Codes CT12/DB12 and CT13/DB13).

Condition 6.2.16 contains specific reporting requirements per 40 CFR 63 Subpart YYYY for the combustion turbines. It was revised to include the new combustion turbines (Source Codes: CT12 and CT13).

Condition 6.2.17 outlines requirements for submitting a notification of compliance status for the combustion turbines. It was revised to include the new combustion turbines (Source Codes: CT12 and CT13).

Condition 6.2.21 requires the Plant to submit reports of special testing time for each combustion turbine. It was revised to correct “running annual” to “average.”

New Conditions 6.2.23 through 6.2.25 were added to provide the recordkeeping and reporting requirements for the new water bath heaters (Source Codes: WBH1 and WBH2) per 40 CFR 63 Subpart DDDDD requirements.

New Condition 6.2.26 was added to require daily recordkeeping of startup, shutdown, and fuel switching for the new combined cycle units (Source Codes CT12/DB12 and CT13/DB13).

New Condition 6.2.27 was added to require recordkeeping of verification of compliance with NO_X emission limits for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Conditions 6.2.28 through 6.2.30 were added to require recordkeeping of verification of compliance with greenhouse gas emission limits for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Conditions 6.2.31 through 6.2.33 were added to require recordkeeping of verification of compliance with operational limits for the combustion turbines (CT12 and CT13).

New Condition 6.2.34 was added to state the quarterly reporting requirements for the combustion Turbines (CT12 and CT13).

New Condition 6.2.35 through 6.2.37 were added to state the 40 CFR 60 Subpart TTTT or TTTTa as applicable, recordkeeping and reporting requirements for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 6.2.38 was added to state the construction and startup notification requirements for the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

New Condition 6.2.39 was added to require recordkeeping of turbine tuning.

Section 7.0: Other Specific Requirements

Condition 7.9.7 was modified to revise the Facility ORIS Code and effective dates.

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

Condition 7.15.1 lists emission units subject to the Cross State Air Pollution Rule (CSAPR). The condition was modified to include the new combined cycle units (Source Codes: CT12/DB12 and CT13/DB13).

APPENDIX A

Draft Revised Title V Operating Permit Amendment
McIntosh Combined Cycle Facility
Rincon (Effingham County), Georgia

APPENDIX B

McIntosh Combined-Cycle Facility PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 959863, dated November 4, 2025

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review