PSD PERMIT APPLICATION

Oglethorpe Power Corporation / Smarr Combined Cycle Energy Facility

PSD Permit Application
Volume I

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1. EXECUTIVE SUMMARY

Oglethorpe Power Corporation (OPC) is proposing to construct a greenfield electrical power plant in Monroe County near Forsyth, Georgia, which will be called the Smarr Combined Cycle Energy Facility (the Facility). The Facility will be a major source under both the Title V operating permit program and the Prevention of Significant Deterioration (PSD) construction permitting program.

The Smarr Combined Cycle Energy Facility will be a natural gas-fired combined cycle facility capable of producing a nominal power output of 1,425 megawatts (MW). The Facility will operate two power blocks each consisting of one combined cycle combustion turbine (CCCT) and one steam turbine, referred to as a "1-on-1" configuration. Each CCCT includes a General Electric (GE) 7HA combustion turbine (CT) exhausting to a heat recovery steam generator (HRSG), which generates steam to power the block's steam turbine. Each HRSG has a duct burner (DB) to provide supplementary firing for additional steam generation as needed. The Facility will also operate two natural gas-fired fuel gas (dew point) heaters, two diesel-fired emergency generators rated at 2,991 engine horsepower (hp) each (2,000 kilowatt [kW] electric output each), and one diesel-fired backup firewater pump rated at 420 hp. The emergency generators are limited to 200 hours per year of operation per engine, and the backup firewater pump is limited to 500 hours per year of operation.

To minimize the formation of oxides of nitrogen (NO_X), each combustion turbine will be equipped with dry low NO_X combustors and each duct burner with low NO_X burners. Each combustion turbine and associated duct burner stack will also be equipped with a selective catalytic reduction (SCR) system for control of NO_X emissions. In addition, each combustion turbine and associated duct burner stack will be equipped with a catalyst system for control of carbon monoxide (CO) and volatile organic carbon (VOC) emissions.

As a greenfield source, once the PSD major source threshold is reached for a particular pollutant, all other PSD pollutants must be evaluated against their respective PSD Significant Emission Rates (SERs). The Smarr Combined Cycle Energy Facility will have potential emissions above the PSD SERs for filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NO_X, VOCs, CO, and greenhouse gases (GHGs) in terms of carbon dioxide equivalents (CO_2e). Therefore, this permitting action is subject to PSD permitting for these pollutants as shown in Table 1-1.

Table 1-1. Proposed Project Emissions

Pollutant	Project Emissions Increases (tpy)[1]	PSD Significant Emission Rate[2] (tpy)	PSD Triggered? (Yes/No)
Filterable PM	200.04	25	Yes
Total PM_{10}	244.22	15	Yes
Total $PM_{2.5}$	244.22	10	Yes
SO_2	26.57	40	No
NO_X	375.68	40	Yes
VOC	146.82	40	Yes
CO	269.90	100	Yes
CO_2e	5,225,407	75,000	Yes
Lead	4.79E-03	0.60	No
Sulfuric Acid Mist	2.66	7.00	No

1. Emissions Increase from New Units (tpy) = New Unit Potential Emissions (tpy)

2. For a greenfield source, once the PSD major source threshold is reached, all other PSD pollutants must be evaluated against their respective SERs. The PSD major source threshold of 100 tpy will be reached by multiple criteria pollutants. PSD for GHGs in terms of CO_2e can only be triggered if PSD is triggered by another PSD pollutant.

OPC is submitting this construction and operating permit application, in accordance with the PSD permitting requirements, to request authorization to construct and operate the Smarr Combined Cycle Energy Facility. The application package contains the necessary state air construction and operating permit application for the proposed project, included in two (2) separate application volumes. This Volume I of the application details the required emissions analyses, regulatory review, and control technology analyses. Volume II of the application package includes all the required air quality assessments necessary as part of this PSD permit application.

1.1 BACT Determination

OPC performed an analysis of Best Available Control Technology (BACT) for each of the regulated pollutants subject to PSD permitting for this proposed project (filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e) following the "top-down" approach suggested by U.S. EPA. The top-down process begins by identifying all potential control technologies for the pollutant in question and making a determination if those control options are technically feasible for the specific process. The approach then involves ranking all technically feasible control technologies in descending order of control effectiveness. The most stringent or "top" control option is typically considered BACT unless energy, environmental, and/or economic impacts justify the conclusion that another control option should be considered BACT. Where the top option is not determined to be BACT, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

Based on the BACT review, OPC proposes the technology and limits presented in Table 1-2 as BACT for the proposed emission units. The detailed BACT analysis is presented in Section 5 of this application.

Table 1-2. Summary of Proposed BACT Limits

Unit	Pollutant	Fuel	Selected BACT	Emission / Operating Limit (per Unit)	Compliance Method
Combined Cycle Combustion Turbines (CCCT1 and CCCT2)	NO_X	Natural Gas	DLN Combustors, SCR, and Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	CEMS, 3-hour rolling average
				182.84 tons during any 12-month consecutive period	CEMS, 12-month rolling total
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Natural Gas	Good Combustion and Operating Practices and Low Sulfur Fuel	27.8 lb/hr	Performance Test
	CO	Natural Gas	Oxidation Catalyst, Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	CEMS, 3-hour rolling average
				130.4 tons during any 12-month consecutive period	CEMS, 12-month rolling total
	VOC	Natural Gas	Oxidation Catalyst, Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	Performance Test
	GHGs	Natural Gas	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	2,608,725 CO_2e tons during any 12-month consecutive period	Fuel Usage Records & 40 CFR 75 Calculation Procedures
				Any applicable requirements of an effective NSPS for GHG emissions	
Emergency Fire Pump (FP1)	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	Purchase of a Certified NSPS IIII Engine	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$				
	CO				
	GHGs			Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel Records
Emergency Generators (EG1 and EG2)	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	Purchase of a Certified NSPS IIII Engine	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$				
	CO				
	GHGs			Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel Records
Fuel Gas Heaters (Dew Point Heaters) (H1 and H2)	NO_X	Natural Gas	Low NO_X Burners	0.049 lb/MMBtu	Performance Test
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$		Good Combustion Practices, Use of Clean Fuel (Natural Gas)	Exclusive Use of Natural Gas	Fuel Records
	CO			0.082 lb/MMBtu	Performance Test
	VOC			Exclusive Use of Natural Gas	Fuel Records
	GHGs				

1.2 Application Contents

Volume I of this permit application is organized as follows:

- Section 2 contains a description of the proposed project;
- Section 3 summarizes emissions calculation methodologies and assesses PSD applicability;
- Section 4 details the regulatory applicability analysis for the proposed project;
- Section 5 contains the required BACT assessment;
- Appendix A includes figures such as an area map and process flow diagram;
- Appendix B includes the detailed potential emissions calculations and New Source Review (NSR) evaluation;
- Appendix C includes the control costs analyses completed in support of the BACT review;

- Appendix D includes the applicable Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database tables; and
- Appendix E contains the Georgia EPD SIP construction permit application forms.

2. PROPOSED PROJECT AND SITE DESCRIPTION

2.1 Project Description

OPC is proposing to construct a new natural gas-fired combined cycle facility capable of producing a nominal power output of 1,425 MW. After obtaining all required pre-construction approvals / permits, OPC expects to commence construction on this project in October 2025. The new Facility will be located in Monroe County near Forsyth, Georgia on land owned by OPC south of Smarr EMC's existing Smarr Energy Facility (AIRS Number: 04-13-207-00030). The Facility will contain two power blocks, each consisting of one CCCT and one steam turbine. Each CCCT includes a GE 7HA combustion turbine exhausting to a heat recovery steam generator, which generates steam to power the block's steam turbine. Each HRSG has a duct burner to provide supplementary firing for additional steam generation as needed. The Facility will also include two natural gas-fired fuel gas (dew point) heaters, two diesel-fired emergency generators rated at 2,991 engine hp each (2,000 kW electric output each), and one diesel-fired backup firewater pump rated at 420 hp.

Other ancillary equipment for the proposed Facility will include air cooled condensers (for process cooling) and electric auxiliary boilers. These ancillary sources will not result in emissions.

2.2 Source Determination

As the proposed Smarr Combined Cycle Energy Facility will be located near an existing permitted power generating facility (Smarr Energy Facility), a discussion of source status is provided within this application. Under the federal rules governing the Title V and PSD permitting programs, facilities may be considered part of the same "Major Source" or "Stationary Source" only if they:[1]

- belong to the same industrial grouping;
- are located on one or more contiguous or adjacent properties; and
- are under the control of the same person (or persons under common control).

The nearby Smarr Energy Facility is owned by Smarr EMC.[2] Smarr Energy Facility is operated by OPC under and in accordance with a Management Services Agreement. Under the Agreement, the operations, maintenance, and regulatory compliance for the Smarr Energy Facility are controlled by Smarr EMC through binding annual budget and plan approvals and additional low-threshold requirements for specific spending authorizations. For example, OPC's service as operator of the Smarr Energy Facility is constrained by annual budgets either approved or established by Smarr EMC, and Smarr EMC's control over the budget also extends to budget revisions. Furthermore, approvals from the Smarr EMC President and Smarr EMC Board of Directors are required in certain instances where the expenditure exceeds amounts as low as $50,000 or $100,000. Likewise, the manner in which OPC is to operate and maintain Smarr Energy Facility must be described in an operation and maintenance plan subject to approval by Smarr EMC. Also, although OPC is required to obtain regulatory permits for the operation of Smarr Energy Facility, responsibility for

[1] Letter from William L. Wehrum, Assistant Administrator, Office of Air and Radiation, EPA, to the Honorable Patrick McDonnell, Secretary, Pennsylvania Department of Environmental Protection (April 30, 2018), available at https://www.epa.gov/sites/production/files/2018-05/documents/meadowbrook_2018.pdf (Meadowbrook Letter).

[2] Smarr EMC was formed in 1998 by a group of EMC distribution cooperatives, which group is a different group from the EMC distribution cooperative members of OPC. Among other corporate separateness characteristics, Smarr EMC has a separate President/CEO and distinct board of directors from OPC. Only members of Smarr EMC can schedule power from the Smarr Energy Facility, which affects the units' dispatch.

compliance under the agreement is cooperative. In short, by contract, Smarr EMC maintains tight control over OPC's operation of Smarr Energy Facility.

In contrast, the new Smarr Combined Cycle Energy Facility will be owned and operated by OPC without any Smarr EMC involvement (Smarr EMC does not have any interest in or connection to the new Smarr Combined Cycle Energy Facility). The operations will be independent, with separate dispatch and separate load purposes. For example, Smarr Energy Facility has simple cycle combustion turbines more suited to peaking capacity. Also, the facilities will not share any common equipment.

As such, there will be no "common control" between the two operations as defined by the U.S. EPA in the 2018 Meadowbrook Letter:

> *For purposes of source determinations, EPA considers "control" to be best understood to encompass the power or authority to dictate the outcome of decisions of another entity. This concept includes only the power to dictate a particular outcome and does not include the mere ability to influence. Thus, control exists when one entity has the power or authority to restrict another entity's choices and effectively dictate a specific outcome, such that the controlled entity lacks autonomy to choose a different course of action.*

Since Smarr EMC controls by contractual rights the operation of the existing Smarr Energy Facility, and since Smarr EMC will have no ability to influence (let alone control) the decisions made for the new Smarr Combined Cycle Energy Facility, there will be no "common control" between the two operations. Therefore, the existing Smarr Energy Facility and the new Smarr Combined Cycle Energy Facility will be considered separate sources with respect to the Title V and PSD permitting programs.

3. EMISSIONS CALCULATION METHODOLOGY

This section addresses the methodology used to quantify the emissions from the proposed project and assesses federal NSR permitting applicability. Emissions from the proposed project will include CO, NO_X, sulfur dioxide (SO_2), VOC, filterable PM, total PM_{10}, total $PM_{2.5}$, lead (Pb), sulfuric acid (H_2SO_4), GHG in the form of CO_2e, hazardous air pollutants (HAPs), and state toxic air pollutants (TAPs). These emissions occur primarily as a result of natural gas combustion in the combustion turbines and duct burners. Detailed emission calculations are presented in Appendix B.

3.1 NSR Permitting Methodology

The NSR permitting program generally requires that a source obtain a permit prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. The NSR program is comprised of two elements: nonattainment NSR (NNSR) and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area the facility is located in is classified as "nonattainment" with the National Ambient Air Quality Standards (NAAQS) for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as "attainment" or "unclassifiable" for the NAAQS. The Smarr Combined Cycle Energy Facility will be located in Monroe County, which is designated as "attainment" or "unclassifiable" for all criteria pollutants.[3] As such, PSD permitting is the NSR program that is potentially applicable to the proposed project.

The following sections discuss the methodology used in the project emissions evaluation conducted to assess PSD applicability under the NSR program. As a greenfield source, once the PSD major source threshold is reached for a particular pollutant, all other PSD pollutants must be evaluated against their respective PSD SERs. The Facility's potential to emit will be above the PSD major source threshold for multiple pollutants and will also be above the PSD SER for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e. As such, PSD permitting requirements apply to the proposed project.

3.2 NSR Calculation Methodology

For purposes of calculating project emissions, different calculation methodologies are used for existing and new units; therefore, it is important to confirm that the sources affected by the proposed project are considered new emission units.

40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units, and are incorporated by reference in the Georgia Rules for Air Quality Control (GRAQC):

> *(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> *(ii) An existing emissions unit is any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

[3] https://www3.epa.gov/airquality/greenbook/anayo_ga.html

The Facility will be a greenfield source, and as such, all proposed emission units will be considered new emissions units for the purposes of PSD applicability. The NSR calculations follow the method outlined in 40 CFR 52.21(a)(2)(iv)(D):

> ***Actual-to-potential test for projects that only involve construction of a new emissions unit(s).*** *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … from each new emissions unit following completion of the project and the baseline actual emissions … these units before the project equals or exceeds the significant amount for that pollutant…*

As such, the NSR calculations will follow an actual-to-potential approach for all proposed emission units. As a greenfield source, the baseline actual emissions from the Facility are zero for all pollutants.

3.2.1 Potential Emissions

Potential emissions are defined by 40 CFR 52.21(b)(4) where the potential to emit:

> *…means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable…*

The NSR calculations for the Facility follow this definition of potential emissions for all proposed emission units.

3.3 NSR Emissions Summary

Table 3-1 shows the total potential emissions of the proposed project compared to the relevant PSD thresholds. As a greenfield source, once the PSD major source threshold is reached for a particular pollutant, all other PSD pollutants must be evaluated against their respective PSD SERs. The Facility will be above the PSD major source threshold for multiple pollutants and will also be above the PSD SER for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e. Detailed emission calculations can be found in Appendix B of this application.

Table 3-1. NSR Emissions Summary

Pollutant	Project Emissions Increases (tpy)[1]	PSD Significant Emission Rate[2] (tpy)	PSD Triggered? (Yes/No)
Filterable PM	200.04	25	Yes
Total PM_{10}	244.22	15	Yes
Total $PM_{2.5}$	244.22	10	Yes
SO_2	26.57	40	No
NO_X	375.68	40	Yes
VOC	146.82	40	Yes
CO	269.90	100	Yes
CO_2e	5,225,407	75,000	Yes
Lead	4.79E-03	0.60	No
Sulfuric Acid Mist	2.66	7.00	No

1. Emissions Increase from New Units (tpy) = New Unit Potential Emissions (tpy)

2. For a greenfield source, once the PSD major source threshold is reached, all other PSD pollutants must be evaluated against their respective SERs. The PSD major source threshold of 100 tpy will be reached by multiple criteria pollutants. PSD for GHGs in terms of CO_2e can only be triggered if PSD is triggered by another PSD pollutant.

3.4 Potential Emissions Estimate

The following sections discuss the methodology used to calculate the potential emissions for each proposed emission unit at the Facility.[4]

3.4.1 Combined Cycle Combustion Turbines

The potential emissions for each CCCT (i.e., combustion turbine with HRSG and duct burner, discharging to a common stack) are determined on a pollutant-by-pollutant basis.

3.4.1.1 Criteria Pollutant Emissions

Table 3-2 summarizes the criteria pollutant emission factors utilized for estimation of potential emissions from the two CCCT units.

[4] The proposed Facility will have other small insignificant sources of emissions (e.g. fugitive piping leaks, roads, etc.) which are not quantified within the potential to emit estimates within this application.

Table 3-2. Criteria Pollutant Potential Emission Factors for CCCT Units

Pollutant	Combined Cycle Turbine System	
	Emission Factor	Unit
NO_X[1]	2	ppmv at 15% O_2
CO[2]	2	ppmv at 15% O_2
VOC[3]	2	ppmv at 15% O_2
Filterable PM / Total PM_{10} / Total $PM_{2.5}$[4]	27.8	lb/hr
SO_2[5]	0.0006	lb/MMBtu
H_2SO_4[5]	0.00006	lb/MMBtu
CO_2e[6]	118.98	lb/MMBtu

[1] Proposed BACT limit for NO_X emissions from the CCCT units. Emission factor translates to 0.0081 lb/MMBtu.

[2] Proposed BACT limit for CO emissions from the CCCT units. Emission factor translates to 0.0050 lb/MMBtu.

[3] Proposed BACT limit for VOC emissions from the CCCT units. Emission factor translates to 0.0029 lb/MMBtu.

[4] Proposed BACT limit for Filterable PM / Total PM_{10} / Total $PM_{2.5}$ emissions from the CCCT units. Emission factor translates to 0.0056 lb/MMBtu.

[5] Default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

[6] Emission factor for GHGs in terms of CO_2e is inclusive of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions. CO_2 emission factor based on Equation G-4 in Appendix G to 40 CFR 75. Emission factors for CH_4 and N_2O based on EPA default factors in 40 CFR Part 98 Subpart C, Table C-2, for Natural Gas. Global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1 (update to AR5 GWP effective January 1, 2025).

The emission factors in Table 3-2 are used to calculate potential emissions, assuming up to 8,760 hours per year of operation at maximum nominal capacity. In cases where the emissions profile of startup / shutdown operations differs from steady-state operation (NO_X, CO, and VOC), specific manufacturer-provided emission factors are used on a per startup / shutdown event basis. For these pollutants, potential emission emissions are calculated using anticipated maximum annual startup / shutdown event counts, durations, and emissions per event. All remaining potential operation time for the year is calculated based on steady-state operation at maximum nominal capacity. Refer to Table 3-3 for additional details on startup / shutdown events.

Table 3-3. Startup / Shutdown Criteria Pollutant Potential Emission Factors for CCCT Units

Pollutant	Emission Factors[1] (lb/event)	Duration[1] (mins)	Events[2] (per CCCT)
Cold Startup			
NO_X	455	70	10 events/yr
CO	1,620		
VOC	520		
Warm Startup			
NO_X	265	60	10 events/yr
CO	660		
VOC	140		
Hot Startup			
NO_X	125	30	10 events/yr
CO	530		
VOC	135		
Shutdown			
NO_X	30	30	30 events/yr
CO	225		
VOC	90		

1. Startup/shutdown emission factors as provided from GE. These factors represent total emissions for the occurrence of a startup or shutdown event.

2. Number of SUSD events based on anticipated operation.

3.4.1.2 HAP and TAP Emissions

HAP and TAP emissions from the CCCTs are calculated separately for the combustion turbines and duct burners.

HAP and TAP emissions from each combustion turbine are calculated based on AP-42 Section 3.1, *Stationary Gas Turbines*, Table 3.1-3, April 2000, for all HAP and TAP except for formaldehyde and hexane. The emission factor for formaldehyde is derived from specific test data in AP-42 Section 3.1, *Stationary Gas Turbines*, April 2000, Related Information, for formaldehyde from all GE Turbines > 20 MW. The emission factor for hexane is determined based on the site-specific gas composition test data for the pipeline-quality natural gas. Considering the fuel input to the CCCTs and the potential unburned hydrocarbons, an emission factor was developed based on the percent of fuel expected to be combusted (i.e., destroyed).

HAP and TAP emissions from each duct burner are calculated based on AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-2, -3, and -4, July 1998, for all HAP and TAP except for hexane. Similarly to the combustion turbines, the emission factor for hexane is determined based on the site-specific gas composition test data for the pipeline-quality natural gas. Considering the fuel input to the CCCTs and the potential unburned hydrocarbons, an emission factor was developed based on the percent of fuel expected to be combusted (i.e., destroyed).

All HAP and TAP potential emissions are calculated assuming up to 8,760 hours per year of operation at maximum nominal capacity.

3.4.2 Fuel Gas (Dew Point) Heaters

In addition to the CCCTs, OPC will operate several ancillary emission units at the proposed Facility to support operations. The Facility will have two natural gas-fired fuel gas (dew point) heaters (7 MMBtu/hr, each), one for each power block.

Criteria pollutant emissions as well as HAP and TAP emissions from the fuel gas heaters are calculated based on AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-1, -2, -3, and -4, July 1998, for all pollutants except for CO_2e.[5] GHG emissions are calculated in terms of CO_2e (inclusive of CO_2, CH_4, and N_2O) based on EPA default factors in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, for Natural Gas. GWP for each pollutant per 40 CFR 98, Subpart A, Table A-1.

Potential emissions from the fuel gas heaters are calculated assuming up to 8,760 hours per year of operation at maximum nominal capacity.

3.4.3 Emergency Engines

The Facility will also include two diesel-fired emergency generators rated at 2,991 engine hp each (2,000 kW electric output each), and one diesel-fired backup firewater pump rated at 420 hp. These units will only operate for emergency purposes as well as standard maintenance and readiness testing.

Criteria pollutant and HAP / TAP emissions for these units are based on a combination of emission factors:

- SO_2 and H_2SO_4[5]
  - From AP-42 Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines*, Tables 3.4-1 and -2, October 1996, for the two diesel-fired emergency generators.
  - From AP-42 Section 3.3, *Gasoline and Diesel Industrial Engines*, Table 3.3-1, October 1996, for the diesel-fired backup firewater pump.
- NO_X, CO, $PM/PM_{10}/PM_{2.5}$, and VOC – from relevant emission standards in 40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)
- CO_2e – GHG emissions are calculated in terms of CO_2e (inclusive of CO_2, CH_4, and N_2O) based on EPA default factors in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, for distillate fuel oil no. 2. GWP for each pollutant per 40 CFR 98, Subpart A, Table A-1.
- HAP and TAP
  - From AP-42 Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines*, Table 3.4-3, October 1996, for the two diesel-fired emergency generators.
  - From AP-42 Section 3.3, *Gasoline and Diesel Industrial Engines*, Table 3.3-2, October 1996, for the diesel-fired backup firewater pump.

[5] Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

Potential emissions are calculated using the maximum nominal capacity of each emergency engine for 200 hours per year for each of the emergency generators, and 500 hours per year for the backup firewater pump.[6]

3.4.4 Facility-wide Potential Emissions

Facility-wide potential emissions for the proposed Facility are shown in Table 3-4. Refer to Appendix B of this Volume for detailed potential emission calculations and NSR analysis.

Table 3-4. Facility-wide Potential Emissions

Pollutant	Annual Emissions (tpy)
SO_2	26.57
NO_X	375.68
CO	269.90
Total PM	244.22
Filterable PM	200.04
Condensable PM	44.18
Total PM_{10}	244.22
Total $PM_{2.5}$	244.22
VOC	146.82
Lead	4.79E-03
Sulfuric Acid Mist (H_2SO_4)	2.66
GHGs (CO_2e)	5,225,407
Total HAP	16.86
Max Single HAP[1]	5.67

1. Max Single HAP is Formaldehyde.

[6] Under Georgia Rule (mmm)7, emergency generators meeting the definition in Rule (mmm)4(i) are exempt from the NO_X emission limit in Rule (mmm)1. Rule (mmm)4(i) defines emergency generators as those that operate only when electric power from the local utility is not available and which operate less than 200 hours per year.

4. REGULATORY APPLICABILITY ANALYSIS

This section of the application summarizes the air permitting requirements and key federal and state air quality regulations that will potentially apply to the proposed Facility. Potential applicability of NSR, Title V, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), Georgia Rules for Air Quality Control (GRAQC), and other potentially applicable regulations to the proposed project are addressed herein.

4.1 New Source Review Applicability

The NSR permitting program generally requires a source to obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in an increase in emissions in excess of certain pollutant threshold levels. Georgia EPD administers its major NSR permitting program through GRAQC Rule 391-3-1-.02(7), *Prevention of Significant Deterioration of Air Quality*, which establishes preconstruction, construction, and operation requirements for new and modified sources.

The NSR program is comprised of two elements: NNSR and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area where the facility is located is classified as "nonattainment" for that pollutant. The PSD program applies to new construction or modifications that result in emission increases of a particular pollutant for which the area where the facility is located is classified as "attainment" or "unclassifiable." The Smarr Combined Cycle Energy Facility will be located in Monroe County, which has been designated by the U.S. EPA as "attainment" or "unclassifiable" for all criteria pollutants.[7] Therefore, the proposed project is not subject to NNSR permitting requirements. However, new construction or modifications that result in emissions increases are potentially subject to PSD permitting requirements.

The PSD program only regulates emissions from "major" stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant is above the major source thresholds. The PSD major source threshold for the facility is 100 tons per year (tpy) for all regulated pollutants, except GHG.[8, 9] The proposed project will require a PSD construction permit as a new major source.

Since the proposed Facility will be a PSD major source for at least one regulated pollutant, the emissions increase for all regulated pollutants resulting from the proposed project must be compared against the PSD SER to determine for which pollutants the project is subject to PSD review. For CO_2e, PSD permitting is only required if the emissions increase from the proposed project is above the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant. The emissions increase from the proposed project for each PSD-regulated pollutant compared to the respective SER are shown in Table 4-1.

[7] 40 CFR 81.311

[8] Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input are on the "List of 28" named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy. The combined-cycle combustion turbine systems that are proposed meet this definition.

[9] 40 CFR 52.21(b)(49)(iii) and (iv)

Table 4-1. Project Potential Emissions Compared to PSD SER

Pollutant	Project Emissions Increases (tpy)[1]	PSD Significant Emission Rate[2] (tpy)	PSD Triggered? (Yes/No)
Filterable PM	200.04	25	Yes
Total PM_{10}	244.22	15	Yes
Total $PM_{2.5}$	244.22	10	Yes
SO_2	26.57	40	No
NO_X	375.68	40	Yes
VOC	146.82	40	Yes
CO	269.90	100	Yes
CO_2e	5,225,407	75,000	Yes
Lead	4.79E-03	0.60	No
Sulfuric Acid Mist	2.66	7.00	No

1. Emissions Increase from New Units (tpy) = New Unit Potential Emissions (tpy)

2. For a greenfield source, once the PSD major source threshold is reached, all other PSD pollutants must be evaluated against their respective SERs. The PSD major source threshold of 100 tpy will be reached by multiple criteria pollutants. PSD for GHGs in terms of CO_2e can only be triggered if PSD is triggered by another PSD pollutant.

As illustrated in Table 4-1, the proposed project emissions increase (and net emission increase) is above the SER for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e. Accordingly, PSD review is required for these pollutants, and this application is an application for a PSD permit.

4.2 Title V Operating Permits

40 CFR 70 establishes the federal Title V operating permit program. Georgia has incorporated the provisions of this federal program in its state regulation, Rule 391-3-1-.03(10), *Title V Operating Permits.* This regulation requires that all new and existing Title V major sources of air emissions obtain federally approved state-administered operating permits. A major source is defined under the Title V program as a facility that has the potential to emit either more than 100 tpy for any criteria pollutant, more than 10 tpy for any single HAP, or more than 25 tpy for combined HAPs. Potential emissions from the Smarr Combined Cycle Energy Facility will be above the major source threshold for several criteria pollutants and it will therefore be a Title V major source. Note that the Facility's potential emissions will not be above the 10 tpy single HAP or 25 tpy combined HAP major source thresholds.

A Title V application to the Georgia Environmental Protection Division (EPD) must be submitted electronically within one year of a facility starting operations as a major source (see GRAQC 391-3-1-.03(10)(c)1.). The application must be submitted using the Georgia EPD Online System (GEOS). This application is not for a Title V operating permit; OPC will timely apply for a Title V operating permit after commencement of operations.

4.3 New Source Performance Standards

NSPS, promulgated in 40 CFR 60, require new, modified, or reconstructed sources to control emissions to the level specified in the applicable provisions. The following is a summary of applicability and non-applicability determinations for NSPS regulations of relevance to the proposed project. Rules that are specific to certain source categories unrelated to the proposed project are not discussed in this regulatory review.

4.3.1 40 CFR 60 Subpart A – General Provisions

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.3.2 40 CFR 60 Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr (Not Applicable)

NSPS Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators*, applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971. However, any facility subject to 40 CFR 60 Subpart KKKK (NSPS Subpart KKKK) is not subject to this subpart.[10] The proposed combined cycle combustion turbines at the Facility (inclusive of both the combustion turbine and the associated HRSG with duct burner) will be subject to NSPS Subpart KKKK. Further, combustion turbines do not meet the definition of fossil fuel-fired steam generating equipment in this rule.[11] The proposed Facility will also involve the installation of two natural gas-fired fuel gas heaters; however, each heater will have a heat input capacity less than 250 MMBtu/hr. Therefore, NSPS Subpart D does not apply.

4.3.3 40 CFR 60 Subpart Da – Electric Utility Steam Generating Units > 250 MMBtu/hr (Not Applicable)

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978. However, any facility subject to NSPS Subpart KKKK is not subject to this subpart.[12]

In addition, NSPS Subpart KKKK states that heat recovery steam generators and duct burners regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart Da.[13] Since the proposed combined cycle combustion turbines at the Facility will be subject to NSPS Subpart KKKK, they are not subject to NSPS Subpart Da.

[10] 40 CFR 60.40

[11] 40 CFR 60.41

[12] 40 CFR 60.40Da(e)(1)

[13] 40 CFR 60.4305(b)

4.3.4 40 CFR 60 Subpart Db – Steam Generating Units > 100 MMBtu/hr (Not Applicable)

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.

While the proposed combined cycle combustion turbines at the Facility would be classified as steam generators, they will not be subject to NSPS Subpart Db because they will be subject to the provisions of NSPS Subpart KKKK and as such, will meet the exemption from this regulation under 40 CFR 60.40b(i).

The two proposed natural gas-fired fuel gas heaters at the Facility will not be subject to NSPS Subpart Db since their heat input capacities are each less than 100 MMBtu/hr.

4.3.5 40 CFR 60 Subpart Dc – Small Steam Generating Units (Not Applicable)

NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989, and for which the maximum design heat input capacity is 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.[14]

While the proposed combined cycle combustion turbines at the Facility would be classified as steam generators, they will not be subject to NSPS Subpart Dc because they will be subject to the provisions of NSPS Subpart KKKK and as such, will meet the exemption from this regulation under 40 CFR 60.40c(e).

The two proposed natural gas-fired fuel gas heaters at the Facility will not be subject to NSPS Subpart Dc since their heat input capacities are each below 10 MMBtu/hr.

4.3.6 40 CFR 60 Subpart GG – Stationary Gas Turbines (Not Applicable)

NSPS Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[15]

The proposed combined cycle combustion turbines at the Facility will be subject to the more recently promulgated standards for stationary combustion turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG.

4.3.7 40 CFR 60 Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (Applicable)

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, is potentially applicable to stationary compression ignition internal combustion engines (ICE) based on the date each engine was constructed, reconstructed, or modified. The rule provides performance standards for both engine manufacturers and operators. Engine operators must meet the specified emission standards and fuel type specifications.

[14] 40 CFR 60.40c(a)

[15] 40 CFR 60.330(a), (b)

The proposed emergency generators and fire water pump engine will be subject to the emission standards in NSPS Subpart IIII. The Facility 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 EPA's Tier 2 emission standards, and the fire water pump engine will be subject to the standards in Table 4 to Subpart IIII for stationary fire pump engines with a rated capacity between 300 hp and 600 hp.

The Facility will comply with all applicable NSPS Subpart IIII monitoring, recordkeeping, reporting, and maintenance requirements, including the requirement to install a non-resettable hour meter on each engine and to operate and maintain the engine in accordance with the manufacturer's emission-related written instructions and change only those emission-related settings that are permitted by the manufacturer.[16] The Facility will be required to only use fuel in the engines meeting the requirements in 40 CFR 60.4207, which requires the use of ultra-low sulfur diesel (ULSD).

Since the engines will be designated and operated as emergency engines, the units will only be operated in emergency circumstances and for a maximum of 100 hours per year for maintenance and readiness testing, of which up to 50 hours may be used for other non-emergency situations.[17]

4.3.8 40 CFR 60 Subpart KKKK – Stationary Combustion Turbines (Applicable)

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18, 2005.[18]

The proposed combined cycle combustion turbines (including both the gas turbine and the associated HRSG with duct burner) will be subject to the requirements of NSPS Subpart KKKK. Applicability to Subpart KKKK is outlined in the following sections. Note that, on November 22, 2024, the U.S. EPA proposed a new NSPS Subpart KKKKa. The rule has not been finalized and, therefore, is not in effect at this time. Should the rule be finalized, OPC will evaluate potential applicability of the rule to the Facility's proposed combined cycle combustion turbines.

4.3.8.1 Emission Limits

Per Table 1 to Subpart KKKK, the NO_X emission limit for the proposed units are as follows.

- For new combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2, or 0.43 lb/MWh useful output.
- For units greater than 30 MW output, the NO_X emission standard is 96 ppm at 15% O_2 or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.

[16] 40 CFR 60.4209(a), 40 CFR 60.4211(a)

[17] 40 CFR 60.4211(f)

[18] 40 CFR 60.4305(a), (b)

Compliance with the NO_X emission limit is determined on a 30 unit operating day rolling average basis.[19] For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.[20]

SO_2 emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input (or 26 ng SO_2/J).[21]

4.3.8.2 Monitoring and Testing Requirements

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

4.3.8.2.1 NO_X Compliance Demonstration Requirements

The proposed combustion cycle combustion turbines will be equipped with continuous emissions monitoring systems (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. As such, compliance with the NO_X emission limit can be demonstrated through the use of the NO_X-diluent CEMS to determine the hourly emission rate in ppm.[22] Pursuant to 40 CFR 60.4345, the Facility can rely on a NO_X CEMS installed and certified according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NO_X emission limit.

Sources demonstrating compliance with the NO_X emission limits via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[23] Initial compliance with the applicable NO_X emission limits will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative accuracy test audit (RATA) to the NO_X emission limit under this subpart.[24]

4.3.8.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular demonstrations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbines must be determined and recorded once per operating day or using a custom schedule as approved by EPD.[25]

[19] 40 CFR 60.4350(h)

[20] 40 CFR 60.4380(b)(3)

[21] 40 CFR 60.5530(a)(1) or (a)(2), respectively.

[22] 40 CFR 60.4340(b)(1)

[23] 40 CFR 60.4340(b), 40 CFR 60.4405

[24] 40 CFR 60.4405(c) and (d)

[25] 40 CFR 60.4370(b) and (c)

However, as allowed per 40 CFR 60.4365, OPC elects to satisfy sulfur content requirements by using pipeline quality natural gas that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2. This demonstration can be made using one of the following methods:

1. By using valid purchase contracts, tariff sheets, or transportation contracts for the fuel, specifying that the natural gas fuel sulfur content is less than or equal to 20 grains per 100 standard cubic feet. This threshold serves as demonstration that the potential emissions will not exceed 0.060 lb/MMBtu.
2. By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed potential emissions of 0.060 lb SO_2/MMBtu heat input.

OPC proposes to satisfy this requirement to monitor the sulfur content of the natural gas burned in the combined cycle combustion turbines through submittal of a semiannual analysis of the gas sulfur content by the Facility or the supplier, or through a valid purchase contract, tariff sheet, or transportation contract for the gaseous fuel, specifying that the maximum sulfur content does not exceed 20 grains per 100 standard cubic feet.

4.3.9 40 CFR 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (Currently Not Applicable)

Currently, NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, applies to stationary combustion turbines that commence construction after January 8, 2014, but on or before May 23, 2023, or commence reconstruction after June 18, 2014, but on or before May 23, 2023.

NSPS Subpart TTTT requires newly constructed stationary combustion turbines to meet the following emissions limitations:[26]

- 450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or
- 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.

Construction of the proposed combined cycle combustion turbines at the Facility will commence after the "on or before" applicability date currently included in NSPS Subpart TTTT; as such, the current version of NSPS Subpart TTTT does not apply at this time.

4.3.10 40 CFR 60 Subpart TTTTa – Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (Currently Applicable)

NSPS Subpart TTTTa, *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units*, currently applies to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that has a base load rating greater than 250 MMBtu/hr of fossil fuel and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system. The final rule was published in the Federal Register on May 9, 2024.

[26] For a newly constructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.

NSPS Subpart TTTTa could apply to the proposed combined cycle combustion turbines at the Facility. However, this new rule is currently under litigation and is being reconsidered by EPA.[27] If this rule were to be overturned or rescinded, the combined cycle combustion turbines could be subject to 40 CFR 60 Subpart TTTT for greenhouse gas emissions.

If the Facility was subject to NSPS Subpart TTTTa, the applicable CO_2 emission limit would depend on the load level at which the new units are operated. The load-specific emission limits applicable to combustion turbines that fire only natural gas are as follows:[28]

- Low load combustion turbines (annual capacity factor ≤ 20%):
  - 50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input as determined by the procedures in 40 CFR 60.5525a.

- Intermediate load combustion turbines (annual capacity factor > 20% and ≤ 40%):
  - 530 kg CO_2/MWh (1,170 lb CO_2/MWh) of gross energy output; or 540 kg CO_2/MWh (1,190 lb CO_2/MWh) of net energy output as determined by the procedures in 40 CFR 60.5525a.

- Base load combustion turbines (annual capacity factor >40%):
  - For 12-operating month averages beginning before January 2032, 360 kg CO_2/MWh (800 lb CO_2/MWh) of gross energy output; or 370 kg CO_2/MWh (820 lb CO_2/MWh) of net energy output as determined by the procedures in 40 CFR 60.5525a.
  - For 12-operating month averages beginning after December 2031, 43 kg CO_2/MWh (100 lb CO_2/MWh) of gross energy output; or 42 kg CO_2/MWh (97 lb CO_2/MWh) of net energy output as determined by the procedures in 40 CFR 60.5525a.

OPC will comply with the requirements of NSPS Subpart TTTTa—if applicable—based on one or more of the load-level options provided in the compliance timeline indicated in Table 1 of NSPS Subpart TTTTa.

4.3.11 Non-Applicability of All Other NSPS

NSPS are developed for specific 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.

4.4 National Emission Standards for Hazardous Air Pollutants

NESHAP, promulgated in 40 CFR 61 and 40 CFR 63, have been promulgated for source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of individual HAP. Facilities with a potential to emit HAP at an amount less than that which is defined as a major source are considered an area source. The NESHAP 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.

[27] https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized

[28] Table 1 to Subpart TTTTa

The proposed Facility will be an area source of HAP emissions. The determination of applicability of NESHAP requirements for the proposed project is described in the following sections. Rules that are specific to source categories unrelated to the proposed project are not discussed in this regulatory review.

4.4.1 40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAP 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.

4.4.2 40 CFR 63 Subpart YYYY – Combustion Turbines (Not Applicable)

NESHAP Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limits for stationary combustion turbines located at major sources of HAP.[29] As the proposed Facility will be an area source of HAP emissions, NESHAP Subpart YYYY does not apply to the proposed combined cycle combustion turbines.

4.4.3 40 CFR 63 Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (Applicable)

NESHAP Subpart ZZZZ, *NESHAP for Stationary Reciprocating Internal Combustion Engines,* applies to stationary reciprocating internal combustion engines (RICE) at major and area sources of HAP. The proposed diesel-fired emergency fire pump and the proposed emergency generators meet the definition of stationary RICE and will be subject to NESHAP Subpart ZZZZ. However, per 40 CFR 63.6590(c)(1), new or reconstructed stationary RICE located at an area source of HAP emissions meet the requirements of NESHAP Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII. As such, these proposed units will be subject to NESHAP Subpart ZZZZ, but this regulation does not impose any additional requirements.

4.4.4 40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (Not Applicable)

NESHAP Subpart DDDDD, *NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Major Source Boiler MACT), regulates boilers and process heaters at major sources of HAP.[30] Boiler is defined in 40 CFR 63.7575 as:

> *[A]n enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition*

[29] 40 CFR 63.6080

[30] 40 CFR 63.7480

The Facility will not operate any boilers as defined in this regulation.[31] The proposed fuel gas heaters would meet the definition of process heaters under this rule; however, the proposed Facility will be an area source of HAP emissions, and the regulation only applies at major sources. As such, NESHAP Subpart DDDDD will not apply.

4.4.5 40 CFR 63 Subpart UUUUU – Electric Utility Steam Generating Units (Not Applicable)

NESHAP Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, applies to electric utility steam generating units (EGUs) that combust coal or oil.[32] Furthermore, pursuant to 40 CFR 63.9983(a), area source stationary combustion turbines, other than integrated gasification combined cycle (IGCC) units, are not subject to NESHAP Subpart UUUUU. As the Smarr Combined Cycle Energy Facility combustion turbines and duct burners will combust natural gas only, and will be located at an area source, NESHAP Subpart UUUUU will not apply.

4.4.6 40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources (Not Applicable)

NESHAP Subpart JJJJJJ, *NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources* (Area Source Boiler MACT), regulates boilers at area sources of HAP.[33] Similar to the discussion in subsection 4.4.4, the proposed Facility will not operate any boilers as defined in 40 CFR 63.11237, which also excludes waste heat boilers:[34]

> *Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

Neither the combined cycle combustion turbines nor the fuel gas heaters will meet this definition. Furthermore, even if the proposed units were to meet this definition, gas-fired boilers are exempt from NESHAP Subpart JJJJJJ.[35] Therefore, the requirements of NESHAP Subpart JJJJJJ will not apply.

4.4.7 Non-Applicability of All Other NESHAP

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

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[31] Any auxiliary boilers at the proposed Facility will be electrically powered.

[32] 40 CFR 63.9980

[33] 40 CFR 63.11193

[34] Any auxiliary boilers at the proposed Facility will be electrically powered.

[35] 40 CFR 63.11195(e)

4.5 Compliance Assurance Monitoring

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), subject facilities are required to prepare and submit monitoring plans for certain emissions units with Title V operating permit applications. Since the proposed Facility is not yet subject to Title V, CAM does not apply at this time and will be reassessed when the Facility submits its initial Title V operating permit application following commencement of operations.

4.6 Risk Management Plan

Section 112(r) of the CAA mandates EPA to publish rules, which are codified in 40 CFR Part 68, applicable to sources with more than the threshold quantity of a listed regulated substance and that regulate the identification, prevention, and minimization of the consequences of accidental releases.

OPC anticipates storing aqueous ammonia at a concentration less than 20% for use in the SCRs, which would not be subject to the RMP requirements. OPC will continue to evaluate potential applicability of RMP provisions throughout the planning, construction, and operation of the proposed project.

4.7 Clean Air Markets Regulations

Starting with the Acid Rain Program mandated by the 1990 Clean Air Act Amendments, U.S. EPA has developed a number of market-based “cap and trade” regulatory programs. All market-based regulatory programs are overseen by U.S. EPA’s Clean Air Markets Divisions (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to the facility are:

- Acid Rain Program (ARP) – 1990 – ongoing
- Cross-State Air Pollution Rule (CSAPR) – 2015 – ongoing

4.7.1 Acid Rain Program

Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the ARP. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The proposed turbines at the Facility will be utility units subject to the ARP. The Facility will be subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring), but will not be subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the proposed turbines do not have the capability to burn coal.

Under 40 CFR 75 of the ARP, the Facility will be required to operate a NO_X-diluent CEMS for each unit to monitor the NO_X emission rate (lb/MMBtu) and to determine SO_2 and CO_2 mass emissions (tons) following the procedures in Appendices D and G, respectively. Further, the ARP will require the Facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also will require initial certification of the monitors within 90 days of commencement of commercial operation, quarterly reports, and an annual compliance certification.

4.7.2 Cross-State Air Pollution Rule

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

To the extent applicable,[36] the Facility will hold sufficient allowances to cover SO_2 and NO_X emissions and will comply with the permitting, monitoring, recordkeeping, and reporting requirements set forth by CSAPR, including the installation and certification of CEMS and fuel flow meters.

4.8 State Regulatory Requirements

In addition to federal air regulations, GRAQC Chapter 391-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level.[37] This section reviews the source specific requirements for the proposed project and does not detail generally applicable requirements such as payment of permit fees.

4.8.1 GRAQC 391-3-1-.02(2)(b) – Visible Emissions (Applicable)

Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. The proposed Facility's combustion turbines will be subject to this regulation as well as the proposed fire pump engine and emergency generators. The duct burners and fuel gas heaters will be subject to the more stringent visible emissions standard in Rule (d).

4.8.2 GRAQC 391-3-1-.02(2)(d) – Fuel-Burning Equipment (Applicable)

Rule (d) limits the PM emissions, visible emissions, and NO_X emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. The GRAQC define "fuel-burning equipment" as follows:[38]

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

The combustion turbines, emergency generators, and emergency fire pump engine are used for the generation of electric power or mechanical power to pump water, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment. The duct burners and fuel gas heaters do, however, meet this definition and are therefore subject to this rule.

The duct burners and fuel gas heaters will be installed or modified after January 1, 1972, making them subject to the PM standards for new units under 391-3-1-.02(2)(d)2. Since each duct burner will have a heat input capacity exceeding 250 MMBtu/hr, each duct burner will be subject to a PM emission limit of 0.10 lb/MMBtu.[39] The PM emission limit for the duct burners is subsumed by the more stringent proposed BACT limit. Since each fuel gas heater will have a heat input capacity less than 10 MMBtu/hr, each heater will be

[36] EPA is reconsidering some or all regulations related to CSAPR: https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized.

[37] Current through rules and regulations filed through February 13, 2025. http://rules.sos.ga.gov/gac/391-3-1

[38] GRAQC 391-3-1-.01(cc)

[39] GRAQC 391-3-1-.02(2)(d)2(iii)

subject to a PM emission limit of 0.50 lb/MMBtu.[40] Compliance will be demonstrated through the exclusive use of natural gas fuel.

All fuel-burning equipment constructed after January 1, 1972 is subject to a visible emissions limit of 20% except for one six minute period per hour of not more than 27% opacity. This limit will apply to the duct burners and fuel gas heaters.[41] This visible emissions requirement will be inherently satisfied because the duct burners and fuel gas heaters will burn exclusively natural gas.

Lastly, fuel-burning equipment that has a heat input capacity greater than 250 MMBtu/hr; that was constructed after January 1, 1972; and that combusts coal, oil, or gas is subject to a NO_X emission limit. Since the duct burners are gas-fired units, they will be subject to a NO_X emission limitation of 0.2 lb/MMBtu.[42] Again, this limit is subsumed by the more stringent NO_X BACT limitation for the combined cycle combustion turbines systems. The proposed fuel gas heaters will not be subject to a NO_X emission limit under Rule (d), as they will each have a heat input capacity less than 250 MMBtu/hr.

4.8.3 GRAQC 391-3-1-.02(2)(e) – Particulate Emissions from Manufacturing Processes (Not Applicable)

Rule (e), commonly known as the process weight rule, establishes PM limits from manufacturing processes where not elsewhere specified. The proposed Facility will not have any manufacturing processes. Therefore, none of the equipment at the proposed Facility will be subject to this regulation.

4.8.4 GRAQC 391-3-1-.02(2)(g) – Sulfur Dioxide (Applicable)

Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. This rule applies to fuel-burning sources as opposed to "fuel-burning equipment." The fuel sulfur content is limited to not more than 3% by weight for fuel-burning sources with a heat input capacity greater than 100 MMBtu/hr and limited to not more than 2.5% by weight for sources with a heat input capacity less than 100 MMBtu/hr.[43] The proposed emission units that burn fuel are all subject to Rule (g). This includes the combined cycle combustion turbines, the emergency generators, the fire pump engine, and the fuel gas heaters. The Facility will comply with this rule through the burning of low sulfur fuels including natural gas (for the combined cycle combustion turbines and fuel gas heaters) and ultra-low sulfur diesel (for the emergency generators and fire pump engine).

4.8.5 GRAQC 391-3-1-.02(2)(n) – Fugitive Dust (Applicable)

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. The proposed Facility will take reasonable precautions to prevent fugitive dust from becoming airborne.

[40] GRAQC 391-3-1-.02(2)(d)2(i)

[41] GRAQC 391-3-1-.02(2)(d)3

[42] GRAQC 391-3-1-.02(2)(d)4(iii)

[43] GRAQC 391-3-1-.02(2)(g)2

4.8.6 GRAQC 391-3-1-.02(2)(tt) – VOC Emissions from Major Sources (Not Applicable)

Rule (tt) limits VOC emissions from facilities that are located in or near the original Atlanta 1-hour ozone nonattainment area. The proposed Facility will not be located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[44]

4.8.7 GRAQC 391-3-1-.02(2)(uu) – Visibility Protection (Applicable)

Rule (uu) requires Georgia EPD to provide an analysis of a proposed major source's (or a major modification to an existing source's) anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The visibility-impacting pollutants include NO_X, PM_{10}, SO_2, and H_2SO_4. Consultation with the appropriate FLMs determined that no analysis of Air Quality Related Values (AQRVs), including visibility, would be required for this project. Therefore, a full review of the anticipated impact on visibility was not performed. Further documentation regarding an evaluation of impacts related to this project on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, is provided in Volume II of this application.

4.8.8 GRAQC 391-3-1-.02(2)(yy) – Nitrogen Oxides from Major Sources (Not Applicable)

Rule (yy) limits NO_X emissions from facilities located in or near the original Atlanta 1-hour ozone nonattainment area. The proposed Facility will not be located within the geographic area covered by this rule and, therefore, will not be subject to this regulation.[45]

4.8.9 GRAQC 391-3-1-.02(2)(jjj) – NO_X from Electric Utility Steam Generating Units (Not Applicable)

Rule (jjj) limits NO_X emissions from coal-fired electric utility steam generating units located in or near the original Atlanta 1-hour ozone nonattainment area. The proposed Facility will not burn coal. Therefore, Rule (jjj) is not applicable.

4.8.10 GRAQC 391-3-1-.02(2)(lll) – NO_X from Fuel-Burning Equipment (Not Applicable)

Rule (lll) limits NO_X emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. The proposed Facility will be located within the geographic area covered by this rule and the fuel gas heaters meet the definition of "fuel-burning equipment." However, the proposed fuel gas heaters will each have a heat input capacity less than 10 MMBtu/hr. Therefore, this rule is not applicable.

4.8.11 GRAQC 391-3-1-.02(2)(mmm) – NO_X Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity (Applicable)

Rule (mmm) establishes ozone season NO_X emission limits on stationary gas turbines and stationary engines with nameplate output capacities between 100 kWe and 25 MWe used for electricity generation and located in certain counties (including Monroe County) in or near the Atlanta metro area.

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[44] GRAQC 391-3-1-.02(2)(tt)3

[45] GRAQC 391-3-1-.02(2)(yy)2

This rule does not apply to the proposed combustion turbines, as they will each have a capacity greater than 25 MW. The rule also does not apply to the emergency fire pump engine, as Rule (mmm)5(iii) exempts stationary engines not connected to an electrical generator.

Rule (mmm) will, however, apply to the proposed emergency generators. Under subsection 7 of the rule, emergency standby stationary engines are exempt from the NO_X emission limits in subsection 1 of the rule. "Emergency standby stationary engines" are currently defined in subsection 4 as any stationary engine that operates only when electric power from the local utility is not available and which operates less than 200 hours per year. The proposed emergency generators will meet this definition; therefore, they will be subject to Rule (mmm) but will not be subject to any NO_X emission limits under the rule.

4.8.12 GRAQC 391-3-1-.02(2)(nnn) – NO_X Emissions from Large Stationary Gas Turbines (Applicable)

Rule (nnn) applies to stationary gas turbines with nameplate capacities greater than 25 MWe located in certain counties, including Monroe County, in or near the Atlanta metro area. Under this rule, stationary gas turbines permitted after April 1, 2000, are subject to an ozone season NO_X emission limitation of 6 ppm at 15% O_2 on a dry basis. The ozone season is defined as May 1 through September 30 of each year. Compliance with this limitation will be demonstrated on a 30-operating day rolling average. The proposed combined cycle combustion turbines will be subject to this limitation.

4.8.13 GRAQC 391-3-1-.02(2)(rrr) – NO_X from Small Fuel-Burning Equipment (Not Applicable)

Rule (rrr) specifies requirements for fuel-burning equipment with capacities of less than 10 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. The proposed Facility will not be located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[46]

4.8.14 GRAQC 391-3-1-.02(2)(sss) – Multipollutant Control for Electric Utility Steam Generating Units (Not Applicable)

Rule (sss) applies to certain large electric utility steam generating units listed within the rule. The Facility will not be subject to this regulation, because none of the proposed units are listed in the regulation.

4.8.15 GRAQC 391-3-1-.02(2)(uuu) – SO_2 Emissions from Electric Utility Steam Generating Units (Not Applicable)

Rule (uuu) applies to certain large electric utility steam generating units listed within the rule. The Facility will not be subject to this regulation, because none of the proposed units are listed in the regulation.

4.8.16 GRAQC 391-3-1-.03(1) – Construction (SIP) Permitting (Applicable)

The proposed project will require physical construction activities to complete. Potential emissions associated with the proposed project are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i).[47] Further, as discussed in Section 4.1, PSD permitting is required for multiple pollutants.

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[46] GRAQC 391-3-1-.02(2)(rrr)2

[47] Based on Georgia EPD guidance, usage of the *de minimis* permitting exemption thresholds must consider actual-to-potential emissions increases, not actual-to-projected actual emissions increases.

Therefore, a construction permit application is necessary, and this application is the required application. The appropriate forms are included in Appendix E.

4.8.17 Incorporation of Federal Regulations by Reference

The following federal regulations are incorporated in the GRAQC by reference and were addressed previously in the application:

- GRAQC 391-3-1-.02(7) – PSD
- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-.02(10) – Chemical Accident Prevention
- GRAQC 391-3-1-.02(11) – CAM
- GRAQC 391-3-1-.02(12) – CSAPR for Annual NO_X
- GRAQC 391-3-1-.02(13) – CSAPR for Annual SO_2
- GRAQC 391-3-1-.02(14) – CSAPR for Ozone Season NO_X
- GRAQC 391-3-1-.13 – ARP

4.8.18 Non-Applicability of Other GRAQC

A thorough examination of the GRAQC applicability to the proposed project reveals many GRAQC that will not apply to the proposed Facility, and do not impose additional requirements on operations. Such GRAQC rules include those specific to a particular type of industrial operation which will not be performed at the proposed Facility or is not impacted by the proposed project.

5. BACT ANALYSIS

This section discusses the regulatory basis for BACT, the approach used in completing the BACT analyses, and the BACT analyses for the combined cycle combustion turbines, fuel gas heaters, emergency generators, and the emergency fire pump engine. Based on the BACT review, OPC proposes the technology and limits presented in Table 5-1 as BACT for the proposed emission units.

Table 5-1. Summary of Proposed BACT Limits

Unit	Pollutant	Fuel	Selected BACT	Emission / Operating Limit (per Unit)	Compliance Method
Combined Cycle Combustion Turbines (CCCT1 and CCCT2)	NO_X	Natural Gas	DLN Combustors, SCR, and Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	CEMS, 3-hour rolling average
				182.84 tons during any 12-month consecutive period	CEMS, 12-month rolling total
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Natural Gas	Good Combustion and Operating Practices and Low Sulfur Fuel	27.8 lb/hr	Performance Test
	CO	Natural Gas	Oxidation Catalyst, Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	CEMS, 3-hour rolling average
				130.4 tons during any 12-month consecutive period	CEMS, 12-month rolling total
	VOC	Natural Gas	Oxidation Catalyst, Good Combustion and Operating Practices	2.0 ppmvd corrected to 15% O_2, excluding periods of startup and shutdown	Performance Test
	GHGs	Natural Gas	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	2,608,725 CO_2e tons during any 12-month consecutive period	Fuel Usage Records & 40 CFR 75 Calculation Procedures
				Any applicable requirements of an effective NSPS for GHG emissions	
Emergency Fire Pump (FP1)	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	Purchase of a Certified NSPS IIII Engine	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$				
	CO				
	GHGs			Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel Records
Emergency Generators (EG1 and EG2)	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	Purchase of a Certified NSPS IIII Engine	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$				
	CO				
	GHGs			Ultra-low sulfur distillate oil (15 ppm sulfur)	Fuel Records
Fuel Gas Heaters (Dew Point Heaters) (H1 and H2)	NO_X	Natural Gas	Low NO_X Burners	0.049 lb/MMBtu	Performance Test
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$		Good Combustion Practices, Use of Clean Fuel (Natural Gas)	Exclusive Use of Natural Gas	Fuel Records
	CO			0.082 lb/MMBtu	Performance Test
	VOC			Exclusive Use of Natural Gas	Fuel Records
	GHGs				

5.1 BACT Requirement

The BACT requirement applies to each new or modified emission unit for which there is an increase in emissions of pollutants subject to PSD review. The proposed Facility will result in potential emissions above the PSD SERs for filterable PM, PM_{10}, $PM_{2.5}$, NO_X, VOC, CO, and GHGs in terms of CO_2e, and thus, is subject to BACT for these pollutants. A BACT review is required for these pollutants for each physically modified or newly constructed emission unit that will emit one or more of these pollutants. Accordingly, a BACT analysis and detailed discussion of each pollutant subject to PSD permitting is assessed herein for the two CCCTs, two natural gas-fired fuel gas heaters, two diesel-fired emergency generators, and one diesel-fired backup firewater pump.

5.2 BACT Definition

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

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

The BACT definition can be best understood by breaking it apart into its separate components.

5.2.1 Emissions Limitation

…emissions limitation…

While BACT is predicated upon the application of technologies to control emissions, the final results of BACT analyses are limits. In general, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant (e.g., tons/year, lb/ton, ppm, lb/hr or lb/MMBtu).[48] Furthermore, U.S. EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling averages.[49]

...*design, equipment, work practice, operational standard, or combination thereof* …

It should be noted that the BACT definition per 40 CFR 52.21(b)(12) identifies that in cases where the implementation of an emission limitation is deemed infeasible, a design, equipment, work practice, operational standard or combination of the same (e.g., use of ULSD) may be prescribed as a BACT standard.

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[48] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a boiler, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[49] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 46.

5.2.2 Each Pollutant

…each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification…

BACT is analyzed for each pollutant, not a combination of pollutants, even where the technology reduces emissions of more than one pollutant. This is particularly important in performing costs analyses. While BACT emission limits for PM_{10} and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM or PM_{10} also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable PM_{10} will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed project is due to NO_X emissions from the turbines. Any secondary PM BACT is effectively addressed by controlling the direct emissions of NO_X, which is addressed through the NO_X BACT analysis conducted for the turbines.

For BACT evaluations involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act is the sum of six greenhouse gases and not a single pollutant.[50] Though the primary GHG emissions from natural gas and fuel oil combustion at the proposed Facility are of CO_2, GHG BACT is discussed separately for the following additional GHG components: CH_4 and N_2O.

5.2.3 Case-by-Case Basis

…a case-by-case basis, taking into account energy, environmental and economic impacts and other costs…

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by U.S. EPA,

> *The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]… The BACT analysis, therefore, involves judgment and balancing.* [51]

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[52] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless energy, environmental, and/or economic impacts indicate that the most stringent control option should not be selected as BACT in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

[50] The six GHGs are: CO_2, N_2O, CH_4, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[51] U.S. EPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, pages 41-42.

[52] Memo dated December 1, 1987, from J. Craig Potter (EPA Headquarters) to EPA Regional Administrators, titled "Improving New Source Review Implementation."

The "top-down" approach is discussed in detail in Section 5.4. While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory or regulatory requirement of the BACT determination. As discussed in Sections 5.2.1 and 5.4.5, the BACT evaluation determines emissions limitations and does not require the installation of any specific control device.

5.2.4 Achievable

…based on the maximum degree of reduction …[that Georgia EPD] … *determines is achievable … through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques…*

BACT is to be achievable. There is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life.

As discussed by the DC Circuit Court of Appeals,

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."* [53]

U.S. EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply,* ***if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility.*** *Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[54]

More recently, this issue was addressed for GHG BACT:[55]

> *Efficiency standards may vary on a case-by-case basis to account for site variability (e.g., altitude) and other factors that could impact process efficiency. In addition, any system will "age" over time and achievable efficiencies may deteriorate. Section 169 contains multiple statutory factors that must be evaluated in determining the "maximum degree of reduction" on which BACT is based. Efficiency improvements in combination with some other control option could be listed as the*

[53] As quoted in Sierra Club v. U.S. EPA (97-1686).

[54] U.S. EPA Environmental Appeals Board decision, In re: Newmont Nevada Energy Investment L.L.C. PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, page 442.

[55] Clean Air Act Advisory Committee (CAAAC) Climate Change Workgroup, *Report of Issue Group 2: Technical Feasibility* https://www.epa.gov/caaac/climate-change-workgroup-reports-and-presentations

maximum control, in which case the standard process limits would likely incorporate the effects of the more efficient design and a separate "efficiency" standard would not be necessary. Page B.l6 of the 1990 Draft NSR Workshop Manual notes that "combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated.[56]

This stance continues to be affirmed by the U.S. EPA Environmental Appeals Board in an order denying review of the PSD permit for the La Paloma Energy Center:[57]

"…the Board has recognized that permitting authorities are not always required to impose the highest possible level of control efficiency, but may take case-specific circumstances into consideration in determining what level of control is achievable for a given source. See In re Russell City Energy Ctr., 15 E.A.D. 1, 58-61 (EAB 2010) ***(rejecting a "bright line" test of requiring the highest or average level of control that another source has achieved),*** *petition denied sub nom. Chabot-Las Positas Cmty, Coll. Dist. V. EPA, 428 F. App'x 219 (9th Cir. 2012); In re Newmont Nev. Energy Inv., LLC, 12 E.A.D. 429, 441 (EAB 2005). ("We recently explained that '[t]he underlying principle of all of these cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology." (citing In re Cardinal FG Co., 12 E.A.D. 153, 170 (EAB 2005))).*

Thus, BACT must be set recognizing that "achievable" means achievable both at the commencement of operation and also over long periods of time, while considering potentially adverse operating scenarios. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to precisely assess the performance that a unit will achieve under all operating conditions. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[58]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 5.5).

5.2.5 Floor

Emissions [shall not] exceed the emissions allowed by any applicable standard under 40 CFR 60 and 61.

When a facility is subject to New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61 and 63), a permit's BACT provisions may not be

[56] https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf

[57] U.S. EPA Environmental Appeals Board decision, In re: La Paloma Energy Center L.L.C. PSD Appeal No. 13-10, decided March 14, 2014. Environmental Administrative Decisions, Volume 16, pages 280-281.

[58] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never faced a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with special care for similar reasons.

less restrictive than any limit applicable under such standards.[59] State SIP limitations must also be considered when determining the floor.

5.3 BACT Assessment Methodology

The primary document referenced for the traditional "top-down" BACT methodology is U.S. EPA's 1990 *NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting*.[60] U.S. EPA has issued the following guidance documents related to the completion of GHG BACT analyses, which also have relevance to other NSR pollutants. The documents utilized as resources in completing the BACT evaluation for the proposed project include:

- PSD and Title V Permitting Guidance For Greenhouse Gases[61]
- Air Permitting Streamlining Techniques and Approaches for Greenhouse Gases: A Report to the U.S. Environmental Protection Agency from the Clean Air Act Advisory Committee; Permits, New Source Reviews and Toxics Subcommittee GHG Permit Streamlining Workgroup; Final Report[62]
- 2010 Group Reports from the Clean Air Act Advisory Committee, Climate Change Work Group[63]

5.4 BACT "Top-Down" Approach

The following sections present the top-down BACT analysis for each pollutant for which this proposed project triggers PSD and is specific to each emission unit, unless otherwise specified. The five steps in such an evaluation can be summarized as follows:[64]

- **Step 1.** Identify all possible control technologies;
- **Step 2.** Eliminate technically infeasible control options;
- **Step 3.** Rank the technically feasible control technologies based upon emission reduction potential;
- **Step 4.** Evaluate ranked control technologies based on energy, environmental, and/or economic considerations; and
- **Step 5.** Select BACT.

This process is typically conducted on a unit-by-unit, pollutant-by-pollutant basis. While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory or regulatory requirement of the BACT determination.

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[59] NESHAP under 40 CFR 63 sometimes regulate NSR pollutants as a surrogate for non-NSR pollutants.

[60] U.S. EPA, October 1990. https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

[61] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.

[62] U.S. EPA, September 2012. https://www.epa.gov/sites/production/files/2014-08/documents/ghg-permit-streamlining-final-report.pdf.

[63] https://www.epa.gov/caaac/climate-change-workgroup-reports-and-presentations.

[64] This five step process can be directly applied to GHGs without any significant modifications, per *PSD and Title V Permitting Guidance for Greenhouse Gases*.

5.4.1 Identification of Potential Control Technologies (Step 1)

Available control technologies with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step. Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. U.S. EPA's RBLC database.
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies.
3. Engineering experience with similar control applications.
4. Information provided by air pollution control equipment vendors with significant market share in the industry.
5. Review of literature from industrial technical or trade organizations.

Trinity Consultants reviewed recently issued air permits and permit files and performed searches of the RBLC database in January 2025 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed project.

- Permit Data between January 2015 and January 2025
- Process Types
  - 15.200 Combined Cycle & Cogeneration (> 25 MW)
    - 15.210 Natural Gas (includes propane and liquefied petroleum gas)
  - 17.100 Large Internal Combustion Engines (> 500 HP)
    - 17.110 Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel)
  - 17.200 Small Internal Combustion Engines (< 500 HP)
    - 17.210 Fuel Oil (ASTM #1,2, includes kerosene, aviation, diesel fuel)
  - 13.300 Gaseous Fuel and Gaseous Fuel Mixtures
    - 13.310 Natural Gas (includes propane and liquefied petroleum gas)
- Process Pollutants: NO_X, $PM/PM_{10}/PM_{2.5}$, CO, VOC, and GHG, including CO_2, CH_4 and N_2O
- Results are for USA only.

Appendix D presents summary tables of relevant BACT determinations for the above emission units.

5.4.2 Elimination of Technically Infeasible Control Options (Step 2)

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated.

5.4.2.1 Demonstrated Technology

Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility. If the control technology has been installed and operated successfully on the type of source under review, it is typically demonstrated and, absent relevant case-by-case differences, could be considered technically feasible.[65]

5.4.2.2 Emerging and Undemonstrated Technology

An undemonstrated technology may only be considered technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available."[66] Control technologies in the research & development (R&D) and pilot scale phases are not considered available. Based on U.S. EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider, for example, the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration."[67] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

5.4.3 Rank of Remaining Control Technologies (Step 3)

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant of interest. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

5.4.4 Evaluation of Most Stringent Control Technologies (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the BACT limit. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified for purposes of setting the BACT limit.

If necessary, economic analyses compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[68]

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[65] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.17.

[66] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.18.

[67] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.18.

[68] U.S. EPA, *OAQPS Control Cost Manual*, 7th edition, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs may be estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of a replacement catalyst, were included where applicable, while raw material costs were generally estimated based upon the unit cost and annual consumption. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i is the annual interest rate and n is the equipment life in years.

The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For required analyses, an interest rate of 7.5% was used as the current Bank Prime Rate based on U.S. Federal Reserve data.

5.4.5 Selection of BACT (Step 5)

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions limit infeasible, in which case a work practice or operating standard can be imposed as BACT.

5.5 Defining the Source

To assist in meeting the BACT limit, the source need not consider production processes or available methods, systems or techniques that would redefine the source. Historical practice, as well as relevant court rulings, have been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that options that would redefine the nature of the source are not appropriate in a BACT determination.

As U.S. EPA notes, a key task for the reviewing agency is to determine which parts of the proposed project are inherent to the applicant's purpose and which parts may be changed without altering that purpose. As discussed by U.S. EPA in an opinion on the Prairie State project, *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[69]

...

When the Administrator first developed [U.S. EPA's policy against redefining the source] *in* Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[70]

Based on precedent set in multiple prior U.S. EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989], U.S. EPA states the following in Prairie State:

For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. [71]

U.S. EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals.[72]

Taken as a whole, the permitting agency is tasked with evaluating which controls are appropriate, but the authority of the agency does not enable the agency to require an applicant to redefine the source.

The proposed Facility includes two, natural-gas fired power blocks each consisting of one combined cycle combustion turbine (CCCT) and one steam turbine, referred to as a "1-on-1" configuration. Each CCCT includes a General Electric (GE) 7HA combustion turbine (CT) exhausting to a heat recovery steam generator (HRSG), which generates steam to power the block's steam turbine. Each HRSG has a duct burner (DB) to provide supplementary firing for additional steam generation as needed. The proposed Facility will also operate two natural gas-fired fuel gas (dew point) heaters, two diesel-fired emergency generators, and one diesel-fired backup firewater pump. The emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, while the proposed fire water pump engine will be operated for a maximum of 500 hours per year.

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[69] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, page 26.

[70] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, page 29.

[71] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

[72] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

The BACT selections are based on these design constraints, and any potential control methods that would require the Facility to redefine these sources or disrupt the Facility's basic business purpose has been explained as such and were not considered further.

5.6 Turbine Systems NO_X Assessment

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 combined cycle 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.

5.6.1 NO_X Formation – Turbine Systems

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

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 forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired combustion turbines.

U.S. EPA finalized NSPS Subpart KKKK with breakpoints in consideration of turbine sizes greater than 850 MMBtu/hr[73], between 50 MMBtu/hr and 850 MMBtu/hr, and less than 50 MMBtu/hr. On November 22, 2024, the EPA proposed the new NSPS Subpart KKKKa. In the proposal, U.S. EPA maintains these same breakpoints. Since the proposed Facility's combustion turbines are each above the 850 MMBtu/hr size range, only units greater than 850 MMBtu/hr are comparable since there are inherent design differences in units at that size and above that can lead to inherently lower NO_X emission levels.

Therefore, the RBLC review was limited to units of comparable size.

5.6.2 Identification of NO_X Control Technologies – Turbine Systems (Step 1)

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the

[73] 850 MMBtu/hr heat input is approximately a 110 MW combustion turbine that is 44 percent efficient.

kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies could potentially be employed for the Facility's turbines. These technologies use various strategies to chemically reduce NO_X to N_2 with or without the use of a catalyst.

Detailed tables of BACT determinations from the RBLC database are provided in Appendix D. Using the RBLC search, as well as a review of technical literature, potentially applicable NO_X control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:[74]

- Water or Steam Injection
- Dry Low-NO_X (DLN) Combustion Technology (such as SoLoNO$_X$™)
- Good Combustion Practices (Base Case)

Post-combustion control options include:

- EM$_X$™/SCONO$_X$™ Technology
- Selective Catalytic Reduction (SCR)
- SCR with Ammonia Oxidation Catalyst (Zero-Slip™)
- Selective Non-Catalytic Reduction (SNCR)
- Multi-Function Catalyst (METEOR™)

Each control technology is described in detail in the following sections.

5.6.2.1 Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection can reduce NO_X emissions by over 60%, the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion.[75] Additionally, water/stream injection results in a decrease in combustion efficiency, an increase in power (due to increased mass flow), and an increase in maintenance requirements due to wear.[76]

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[74] An additional combustion control technology potentially identified was XONON which was offered by Catalytica Energy Systems. Catalytica merged with NZ Legacy in 2007 to form Renergy Holdings Inc. In November 2007, Renergy sold its SCR catalyst and management services business (SCR-Tech, LLC). SCR-Tech, LLC was acquired by Steag Energy Services, LLC in 2016. Based on research, there is no company which currently makes XONON. As such, it is not considered available for this BACT analysis.

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

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

5.6.2.2 Dry Low-NO_X (DLN) Combustors[77]

The lean premix technology, also referred to as dry low-NO_X combustion technology, is a pollution prevention technology that minimizes NO_X emissions by reducing the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor. In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air decreases the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area. Since NO_X formation rates are an exponential function of temperature, a considerable reduction in NO_X can be achieved by the lean pre-mix system. Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

5.6.2.3 Good Combustion Practices

Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_X emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios.

5.6.2.4 EM_X^{TM}/$SCONO_X$

EM_X^{TM} (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as ammonia (NH_3). The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize NO_X (to potassium nitrate [$K(NO_3)$]) and CO (to CO_2).[78] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[79] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The $SCONO_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[80]

Estimates of control efficiency for a $SCONO_X$ system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78% for NO_X reductions down to 2.0 ppm, and even higher NO_X reductions down to 1 ppm for some designs.[81]

5.6.2.5 Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and NO react to form diatomic N_2 and H_2O vapor. The overall chemical reaction can be expressed as:

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

[78] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[79] Ibid. (Georgia EPD)

[80] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

[81] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[82] Optimal temperatures for SCR units ranges from 480°F to 800°F and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200°F.[83] SCR can be used to reduce NO_X emissions from combustion of natural gas and light oils (e.g., distillate). Combustion of heavier oils can produce high levels of particulate, which may foul the catalyst surface, reducing the NO_X removal efficiency.[84] Other considerations include the possibility for ammonia slip, which refers to emissions of unreacted ammonia escaping with the flue gas and its contribution to secondary particulate formation.[85]

5.6.2.6 SCR with Ammonia Oxidation Catalyst (Zero-Slip™)

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) is a refinement on standard post-combustion SCR technology developed by Cormetech and Mitsubishi Power Systems to reduce ammonia slip associated with traditional SCR systems. The Zero-Slip™ technology consists of a second bed of catalyst that is installed after the main SCR catalyst to further react NO_X with the ammonia. This results in NO_X emissions on par with standard SCR systems and less ammonia slip (less than 2.0 ppmvd at 15% O_2).[86]

5.6.2.7 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

Step 1: Urea Decomposition

$$CO(NH_2)_2 + 2\ H_2O \rightarrow 2\ NH_3 + CO_2$$

Step 2 (or single step if using ammonia):

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[87] An important consideration for implementing SNCR is the operating temperature

[82] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[83] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[84] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[85] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.)

[86] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 13-14.

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

range. The optimum temperature range is approximately 1,600 to 2,000°F.[88] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X.

5.6.2.8 Multi-Function Catalyst (METEOR™)

METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc., and optimized by Cormetech. The METEOR™ catalyst uses ammonia, similar to standard SCR systems, to reduce NO_X emissions but is also able to reduce CO, VOC, and ammonia emissions using a single catalyst bed (i.e., eliminate the need for a separate oxidation catalyst system if CO and VOC reductions are required), resulting in reduced pressure drop and parasitic load requirements.[89] The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs.[90]

5.6.3 Elimination of Technically Infeasible NO_X Control Options – Turbine Systems (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 or if a control technology has not been commercially demonstrated to be achievable.

5.6.3.1 Water or Steam Injection Feasibility

Water or steam injection is a NO_X reduction technology that is commonly used to control NO_X emissions when fuel oil is burned, but is not as effective as DLN combustors when firing natural gas.[91] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[92] Since the proposed turbines exclusively fire natural gas and have DLN combustors that reduce NO_X emissions further than water or steam injection would, water or steam injection is considered to be infeasible.

5.6.3.2 Dry Low NO_X Combustion Technology Feasibility

Dry low NO_X combustion technology is a NO_X control technology that is integral to the combined cycle combustion turbines. It is determined to be technically feasible for the proposed combined cycle combustion turbines for natural gas combustion, which is the only proposed fuel. Therefore, DLN combustion technology

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

[89] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

[90] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 15-16.

[91] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12.

[92] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12.

is included in the following BACT steps and represents part of the base case for NO_X performance as it is inherent in the operation of the combustion systems.

5.6.3.3 Good Combustion Practices Feasibility

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the minimization of NO_X emissions from the turbines.

5.6.3.4 EM_X™/$SCONO_X$™ Technology Feasibility

As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired units, but there are engineering challenges associated with applying this technology to larger plants with full scale operation. To date, this technology has not been installed and operated on a large combined-cycle operation.[93] Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of NO_X emissions from the proposed combined cycle combustion turbines.

5.6.3.5 SCR Feasibility

SCR for NO_X control is a technology that is commonly employed at large combined cycle combustion turbine facilities and is technically feasible for the proposed project. The use of SCR is also included in the project.

5.6.3.6 SCR with Ammonia Oxidation Catalyst (Zero-Slip™) Feasibility

Based on OPC's review of available control technologies, to date, the Zero-Slip™ catalyst technology has not been demonstrated on large, utility-size CCCT units, with full scale operation demonstrated on a 7.5 MW Solar Taurus combustion turbine.[94] As the technology has not been demonstrated on large, utility size units, and it would not achieve NO_X emission rates lower than that achieved by conventional SCR designs, the Zero-Slip™ technology option is not considered a technically feasible control option.

5.6.3.7 SNCR Feasibility

The temperature range required for effective operation of this technology, 1,600 to 2,000°F, is above the peak exhaust temperature for the proposed combined cycle combustion turbines.[95] In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, *Stationary Gas Turbines*, April 2000, shows that SNCR has not been demonstrated on a turbine of this size. Given the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical, reduces the energy efficiency of combined cycle generating units, and would not provide control superior to the installed SCR system, SNCR is eliminated as a technically feasible option for control of NO_X emissions from the proposed combined cycle combustion turbine systems.

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[93] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[94] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 14.

[95] Ibid. (SNCR Fact Sheet)

5.6.3.8 Multi-Function Catalyst (METEOR™) Feasibility

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[96, 97] A review of the RBLC database for CCCTs similar to the proposed combined cycle combustion turbine systems did not return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst, and it would not achieve NO_X emission rates lower than that achieved by conventional SCR designs, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

5.6.4 Summary and Ranking of Remaining NO_X Controls – Turbine Systems (Step 3)

Of the control technologies available for NO_X emissions, the options technically feasible for each unit are shown in Table 5-2

Table 5-2. Remaining NO_X Control Technologies

Control Technology	Technically Feasible for Turbine Systems
Water or Steam Injection	No
DLN Combustion Technology	Yes
Good Combustion Practice	Yes
EM_X™/$SCONO_X$™ Technology	No
SCR	Yes
SCR with Zero-Slip™	No
SNCR	No
METEOR™	No

As shown in Table 5-2, the remaining potentially feasible control technologies could include SCR, DLN combustors, and good combustion practices.

5.6.5 Evaluation of Most Stringent NO_X Controls – Turbine Systems (Step 4)

As stated previously, SCR, DLN combustors, and good combustion practices remain the most stringent NO_X controls that are technically feasible options for the proposed combined cycle combustion turbine systems.

Since the top control options are being proposed for NO_X emissions from the proposed combined cycle combustion turbines, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

DLN Combustors, SCR, and Good Combustion and Operating Practices is selected as BACT for the proposed combined cycle combustion turbine systems.

[96] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 16.

[97] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

5.6.6 Selection of Emission Limits and Controls for NO_X BACT – Turbine Systems (Step 5)

Based on the RBLC search results, NO_X emission limits for combined cycle combustion turbine systems with similar controls range from 2.0 to 3.0 ppmvd, corrected to 15% O_2, while firing natural gas. The most common NO_X limit is 2.0 ppmvd with some units permitted at 2.5 ppmvd and 3.0 ppmvd. There were no units permitted below 2.0 ppmvd. Based on this information, OPC proposes the following as NO_X BACT for each of the proposed combined cycle combustion turbine systems:

- 2.0 ppmvd NO_X or less, corrected to 15% O_2, based on a 3-hour rolling average (CEMS), excluding periods of startup and shutdown;
- 182.84 tons NO_X or less per CCCT during any 12-month consecutive period, including periods of startup and shutdown.

The proposed BACT limit of 2.0 ppmvd does not apply during periods of startup/shutdown. An additional BACT limit would account for the non-steady state operations during periods of startup and shutdown resulting in a substantially different NO_X emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. OPC therefore proposes an additional BACT limit of 182.84 tpy per CCCT on a rolling 12-month basis, inclusive of all operational conditions including startup and shutdown.

Startup means the period of time from when fuel is first fired to the time until the turbine control system indicates emissions compliant mode has been achieved (i.e., the minimum emissions compliance load or MECL) and ammonia injection has occurred.[98]

5.7 Turbine Systems CO Assessment

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.

5.7.1 CO Formation – Turbine Systems

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

5.7.2 Identification of CO Control Technologies – Turbine Systems (Step 1)

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

[98] OPC will prepare and propose suggested permit conditions, including for defining periods of startup and shutdown.

5.7.2.1 Oxidation Catalyst

An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form CO_2.

5.7.2.2 EM_X^{TM}/$SCONO_X^{TM}$

EM_X^{TM} (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, discussed in Section 5.6.2.4.

5.7.2.3 Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NO_X emissions. Accordingly, it is important to optimize oxygen availability with input air, while controlling temperature to minimize NO_X formation.

5.7.3 Elimination of Technically Infeasible CO Control Options – Turbine Systems (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

5.7.3.1 Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[99] This is consistent with the exhaust parameters of the proposed combined cycle combustion turbine systems. Therefore, oxidation catalyst is considered technically feasible for installation on the proposed combined cycle combustion turbine systems and will be considered further in Step 4.

5.7.3.2 EM_X^{TM}/$SCONO_X^{TM}$

The EM_X^{TM}/$SCONO_X^{TM}$ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_X, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X^{TM}/$SCONO_X^{TM}$ catalyst system has operated successfully on several smaller, natural gas-fired combined cycle units, but there are engineering challenges associated with applying this technology to larger plants with full scale operation.[100]

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[99] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: https://www3.epa.gov/ttncatc1/cica/files/fcataly.pdf

[100] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

Consequently, it is concluded that EM_X^{TM}/$SCONO_X^{TM}$ is not technically feasible for control of CO emissions from the proposed combined cycle combustion turbine systems.

5.7.3.3 Combustion Process Design and Good Combustion Practices

This represents the base case for design and operation of the proposed combined cycle combustion turbine systems.

5.7.4 Summary and Ranking of Remaining CO Controls – Turbine Systems (Step 3)

As detailed in Step 2, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it is evaluated further in the BACT process.

5.7.5 Evaluation of Most Stringent CO Controls – Turbine Systems (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology. Since the top control options are being proposed for CO emissions from the proposed combined cycle combustion turbine systems, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

5.7.6 Selection of Emission Limits and Controls for CO BACT – Turbine Systems (Step 5)

CO BACT for the proposed combined cycle combustion turbine systems is based on the use of clean fuels, good combustion practices and use of an oxidation catalyst. Based on the RBLC search results, CO emission limits for combined cycle combustion turbine systems with similar controls range from 0.9 to 25 ppmvd while firing natural gas. The most common limit is 2.0 ppmvd, corrected to 15% O_2, followed by 4.0 ppmvd. There were a few permits with limits lower than 2.0 ppmvd, however, these permits were generally for units located in ozone nonattainment areas and/or did not have duct burner firing. While ozone nonattainment areas don't generally control for CO emissions, they do control for VOC emissions and this likely impacts achievable CO emission rates because the oxidation catalyst reduces both VOC and CO emissions. In addition, Georgia Power Company submitted an application to Georgia EPD for a combined cycle combustion turbine project and they proposed as BACT for CO emissions 2.0 ppmvd CO or less based on a 24-hour rolling average, excluding periods of startup and shutdown. This is the same level being proposed in this application.

Based on this information, OPC proposes the following as CO BACT for each of the proposed combined cycle combustion turbine systems:

- 2.0 ppmvd CO or less, corrected to 15% O_2, based on a 3-hour rolling average (CEMS), excluding periods of startup and shutdown, and
- 130.4 tons CO or less per CCCT during any 12-month consecutive period, including periods of startup and shutdown.

The proposed BACT limit of 2.0 ppmvd does not apply during periods of startup/shutdown. An additional BACT limit would account for non-steady state operations during periods of startup and shutdown resulting in a substantially different CO emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. OPC therefore proposes an additional BACT limit of 130.4 tpy per CCCT on a rolling 12-month basis, inclusive of all operational conditions including startup and shutdown.

Startup means the period of time from when fuel is first fired to the time until the turbine control system indicates emissions compliant mode has been achieved (i.e., the minimum emissions compliance load or MECL) and ammonia injection has occurred.

5.8 Turbine Systems VOC Assessment

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 combined cycle combustion turbine system. The following sections detail the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for VOC.

5.8.1 VOC Formation – Combustion Turbines

VOC from combined cycle combustion turbines is a result of incomplete combustion. Conditions leading to incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

5.8.2 Identification of VOC Control Technologies – Turbine Systems (Step 1)

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

5.8.2.1 Oxidation Catalyst

An oxidation catalyst is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed prompting the VOC to react with oxygen present in the exhaust stream, converting to carbon dioxide and water vapor. The overall control efficiency of such systems on VOC constituents is dependent on the individual VOC components. For example, research completed by U.S. EPA as part of MACT rulemakings found that control of formaldehyde emissions typically exceeds 90%, but other pollutants such as benzene may not see any beneficial reductions. Hence, the overall range of VOC control can vary substantially.[101]

5.8.2.2 EM_X^{TM}/$SCONO_X^{TM}$

EM_X^{TM} (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO, as well as VOC without a reagent, discussed in Section 5.6.2.4.

5.8.2.3 Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of VOC, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Proper operation and good combustion practices provide additional VOC control via the use of gaseous fuels for good mixing and proper combustion techniques such as optimizing the air to fuel ratio.

[101] U.S. EPA Office of Air Quality Planning and Standards Memorandum, *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines,* August 21, 2001.

5.8.3 Elimination of Technically Infeasible VOC Control Options – Turbine Systems (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

5.8.3.1 Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[102] This is consistent with the exhaust parameters of the proposed combined cycle combustion turbine systems. Therefore, oxidation catalyst is considered technically feasible for installation on the proposed combined cycle combustion turbine systems and will be considered further in Step 4.

5.8.3.2 EM_X™/$SCONO_X$™

The EM_X™/$SCONO_X$™ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_X, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired combined cycle units, but there are engineering challenges associated with applying this technology to larger plants with full scale operation.[103]

Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of CO emissions from the proposed combined cycle combustion turbine systems.

5.8.3.3 Combustion Process Design and Good Combustion Practices

This represents the base case for design and operation of the proposed combined cycle combustion turbine systems.

5.8.4 Summary and Ranking of Remaining VOC Controls – Turbine Systems (Step 3)

As detailed in Step 2, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it is evaluated further in the BACT process.

5.8.5 Evaluation of Most Stringent VOC Controls – Turbine Systems (Step 4)

The top control options are being proposed for VOC emissions from the proposed combined cycle combustion turbine systems. Therefore, no further evaluation of the energy, environmental, and economic impacts of the control options is required.

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[102] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: https://www3.epa.gov/ttncatc1/cica/files/fcataly.pdf

[103] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

5.8.6 Selection of Emission Limits and Controls for VOC BACT – Turbine Systems (Step 5)

VOC BACT for the proposed combined cycle combustion turbine systems is based on use of clean fuels, good combustion practices, and use of an oxidation catalyst. Based on the RBLC search results, VOC emission limits for combined cycle combustion turbine systems with similar controls ranged from 0.7 to 4 ppmvd while firing natural gas. The most common limit is 2.0 ppmvd, corrected to 15% O_2. There were some permits with limits lower than 2.0 ppmvd, however, these permits were generally for units located in ozone nonattainment areas and/or did not include duct burner firing. This project will be located in an attainment area for ozone and includes duct burner firing.

Based on this information, OPC proposes the following as VOC BACT for each of the proposed combined cycle combustion turbine systems:

- 2.0 ppmvd VOC (as CH_4) or less, corrected to 15% O_2, based on the average of a 3-run stack test using EPA Reference Method 25A, excluding emissions during periods of startup and shutdown.

Also, it should be noted that since the combined cycle combustion turbine systems will be equipped with CO CEMS and since the oxidation catalyst for control of CO emissions will also control VOC emissions, one way compliance with the VOC BACT emission limits can be assured is by the CO CEMS showing that CO emissions are in compliance with the corresponding CO BACT emission limits. OPC proposes to conduct a one-time stack test after initial startup to confirm emission performance.

5.9 Turbine Systems Filterable PM and Total PM_{10}/$PM_{2.5}$ Assessment

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 CCCT. 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}/$PM_{2.5}$.

While BACT emission limits for PM_{10} and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM or PM_{10} also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable PM_{10} will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed project is due to NO_X emissions from each CCCT. The project does not trigger PSD review for the $PM_{2.5}$ precursor SO_2, as project emissions increases are less than the applicable SO_2 SER threshold. The use of pipeline quality natural gas will help to minimize SO_2 and secondary PM formation.

5.9.1 PM Formation – Turbine Systems

Filterable PM, PM_{10}, and $PM_{2.5}$ emissions from natural gas combustion result primarily from incomplete combustion and by ash and sulfur in the fuel.[104] Combustion of natural gas generates low PM emissions in comparison to other fuels due to the low ash and sulfur content of the fuel.

In contrast to filterable particulate, condensable particulate is the portion of PM emissions that exhausts from the stack in gaseous form but condenses to form particulate matter once mixed with the cooler

[104] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000.

ambient air. Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4; NO_X being oxidized to nitric acid (HNO_3); and high molecular weight organics. A combustion turbine operating without an SCR will have lower condensable PM emissions than a similar unit operating with an SCR. The increased condensable PM emissions result from the formation of ammonium sulfates from unreacted ammonia in the control system. Accordingly, emission estimates for total PM_{10}/$PM_{2.5}$ when utilizing an SCR for NO_X emissions reductions are typically higher than the total PM_{10}/$PM_{2.5}$ emissions anticipated from turbine systems that do not utilize NO_X controls.

5.9.2 Identification of PM Control Technologies – Turbine Systems (Step 1)

The following PM_{10}/$PM_{2.5}$ control technologies were identified based on RBLC search (per the search criteria specified in Section 5.4.1), a limited review of information published in technical journals, and experience in conducting control technology reviews for similar types of equipment. Taking into account the physical and operational characteristics of the units, the candidate control options for particulate matter reduction include:

- Multicyclone
- Wet Scrubber
- Electrostatic Precipitator (ESP)
- Baghouse
- Low sulfur fuel
- Good combustion and operating practices

5.9.2.1 Multicyclone

Multicyclones consist of several small cyclones operating in parallel. The cyclone creates a double vortex inside its shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls. While this is effective for larger particles, smaller particles tend to be overtaken by the fluid drag force of the air stream and will depart the cyclones with the exiting air stream. The particulate removal in cyclones can be improved by having more complex gas flow patterns. The control efficiency range for high efficiency single cyclones is 30 - 90% for PM_{10} and 20 - 70% for $PM_{2.5}$. The use of multicyclones leads to greater PM control efficiency than from a single cyclone, resulting in control efficiencies in the range of 80-95% for particles greater than 5 microns in diameter (PM_5). Multicyclones in parallel can typically handle a higher flowrate when compared to a single cyclone unit, up to approximately 106,000 standard cubic feet per minute (scfm). The allowable inlet gas temperature for a cyclone is limited by the type of construction material but can be as high as 540°C (1,000°F). Cyclones are generally used as precleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower control efficiency of smaller particles from a cyclone.[105]

5.9.2.2 Wet Scrubber

Wet (in particular, venturi) scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The PM collection efficiencies of Venturi scrubbers range from 70% to greater than 99%, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 µm ($PM_{0.5}$) to 5 µm (PM_5). Inlet gas temperatures for

[105] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

wet scrubbers usually range from 4 to 400°C (40 to 750°F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.[106]

5.9.2.3 ESP

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, gas temperature, and plate dimensions. An ESP can be designed for either dry or wet applications.[107] An ESP can generally achieve approximately 99-99.9% reduction efficiency for PM emissions. Typical ESPs can handle approximately 1,000 to 100,000 scfm, at high temperatures up to 700°C (1,300°F).[108]

5.9.2.4 Baghouse (Fabric Filter)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches a certain level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags suffered in the cleaning process.[109] Typically, gas temperatures up to 260°C (500°F) can be accommodated routinely in a baghouse. The fabric filters have relatively high maintenance requirements (for example, periodic bag replacement), and elevated temperatures above the designed temperature can shorten the fabric life. Additionally, a baghouse/fabric filter cannot be operated in moist environments where the condensation of moisture could cause the filter to be plugged, reducing efficiency. Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[110]

Depending on the need, baghouses are available as standard units from the factory, or custom baghouses designed for specific applications. Standard baghouses can typically handle 100 to 100,000 scfm; while custom baghouses are generally larger, ranging from 100,000 to over 1,000,000 scfm.[111]

5.9.2.5 Low Sulfur Fuels

Combusting pipeline-quality natural gas with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form SO_2 and H_2SO_4.

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[106] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Venturi Scrubbers, EPA-452/F-03-017.

[107] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[108] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Pipe Type, EPA-452/F-03-027.

[109] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[110] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

[111] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

5.9.2.6 Good Combustion and Operating Practices

Good combustion and operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

A properly operated combustion unit will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

5.9.3 Elimination of Technically Infeasible PM Control Options – Turbine Systems (Step 2)

All four of the add-on control technologies (multicyclones, wet scrubbers, ESPs, and baghouses) are technically infeasible for controlling filterable particulate from natural gas combustion. Although the add-on control technologies identified are utilized in a number of processes to control particulate emissions, none of these add-on control technologies are applicable to natural gas-fired combustion turbines. Combustion of natural gas generates relatively low levels of particulate emissions in comparison to other fuels due to its low ash and sulfur contents. In addition, turbines operate with a significant amount of excess air, which generates large exhaust flow rates. The low level of particulate emissions combined with the large exhaust gas volume results in very low concentrations of particulate.

Due to the low particulate concentration in the exhaust gas, add-on filterable particulate controls would not provide any significant degree of emission reduction for the combustion turbine systems and are, therefore, not considered further in this analysis.[112]

5.9.4 Summary and Ranking of Remaining PM Controls – Turbine Systems (Step 3)

Of the control technologies available for $PM_{10}/PM_{2.5}$ emissions, the options technically feasible for each unit are shown in Table 5-3.

Table 5-3. Remaining Particulate Matter Control Technologies

Control Technology	Technically Feasible for Combustion Turbine
Multicyclones	No
Wet Scrubber	No
ESP	No
Baghouse	No
Low Sulfur Fuel	Yes
Good Combustion and Operating Practices	Yes

As shown in Table 5-3, the remaining feasible control technologies include low sulfur fuels and good combustion and operating practices. Good combustion and operating practices in conjunction with low sulfur natural gas combustion represents the base case for the combustion turbine system, including the turbine

[112] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, page 43.

and duct burner associated with the HRSG. Therefore, as this is the highest ranking feasible control remaining, it is selected as BACT.

5.9.5 Evaluation of Most Stringent PM Controls – Turbine Systems (Step 4)

As stated previously, good combustion and operating practices with low sulfur natural gas for the combustion turbine systems including the turbine and duct burner associated with the HRSG was determined as the most stringent filterable PM and total PM_{10}/$PM_{2.5}$ control that is a technically feasible option.

5.9.6 Selection of Emission Limits and Controls for PM BACT – Turbine Systems (Step 5)

As the selected BACT for particulate matter emissions relies on good combustion and operating practices in conjunction with the use of low sulfur natural gas, OPC searched U.S. EPA's RBLC database for similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas CCCT systems are provided in the RBLC summary table in Appendix D. Review of the RBLC entries confirms that add-on control for particulate emissions is not required / feasible for natural gas-fired CCCT systems. Typical listings denote "good combustion practices" or similar variants. Some entries may also denote the use of pipeline quality natural gas or inlet air filtration. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being proposed by OPC. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix D to identify potentially comparable units to the proposed combustion turbines:

- Units are large (>850 MMBtu/hr) combined cycle units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

PM BACT for the proposed CCCT units is based on the use of clean fuels with inherently low sulfur content and good combustion practices. Based on the RBLC search results, total PM emission limits for combined cycle combustion turbine systems with similar controls range from 0.0036 lb/MMBtu to 0.0085 lb/MMBtu heat input while firing natural gas. The proposed limit of 27.8 lb/hr (equivalent to 0.0056 lb/MMBtu) is at the lower end of this range.

Based on this information, OPC proposes the following as PM BACT for each of the proposed CCCT units:

- Filterable PM, as well as total PM_{10} and total $PM_{2.5}$, equal to or less than 27.8 lb/hr (equivalent to 0.0056 lb/MMBtu), based on the average of a 3-run stack test using EPA Reference Methods 5 and 202.

Since the PM/PM_{10}/$PM_{2.5}$ BACT is based on the use of clean fuels with inherently low sulfur content, OPC proposes to conduct a one-time stack test after initial startup to confirm emission performance.

5.10 Turbine Systems GHG Assessment

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

CO_2 production from combustion occurs by a reaction between carbon in any fuel and oxygen in the air and proceeds stoichiometrically (i.e., for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[113] CH_4 can be emitted when natural gas is not burned completely in combustion.[114] The last primary component for calculating greenhouse gas emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete combustion situations, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[115]

5.10.1 Turbine Systems CO_2 BACT

The following section presents BACT evaluations for CO_2 emissions from the proposed combined cycle combustion turbine systems.

5.10.1.1 Identification of Potential CO_2 Control Technologies – Turbine Systems (Step 1)

OPC searched for potentially applicable emission control technologies for CO_2 from combined cycle combustion turbines by researching the U.S. EPA control technology database, guidance from U.S. EPA and other sources as described in Section 5.4.1 of this report, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience.

The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are summarized in Appendix D, detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHGs were described for any of the facilities. Many facilities listed a variant of good combustion practices, efficient operation, efficient design, or low emitting fuels (e.g., pipeline-quality natural gas).

OPC used a combination of published resources and general knowledge of industry practices to generate a list of potential controls for CO_2 emitted from combined cycle combustion turbine systems. OPC excluded options such as battery storage, solar power generation, and hydrogen generation/ combustion from the GHG control technology assessment as they are examples of approaches that would redefine the source: The proposed Facility is a natural gas fired electric generating facility utilizing combined cycle combustion turbine systems. U.S. EPA has affirmed that evaluation of control options for lower-emitting GHG processes, such as solar power, that would redefine the source is not a requirement of the BACT review in their response to comments on the proposed Palmdale Hybrid Power Project, subsequently upheld in an order

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

[114] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998.

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

denying review of the PSD permit.[116] Other more recent legal decisions have denied similar petitions for review. [117]

The following potential CO_2 control strategies were considered as part of this BACT analysis:

- Carbon Capture and Storage (CCS); and
- Efficient Turbine Design and Good Combustion, Operating, and Maintenance Practices.

5.10.1.1.1 Carbon Capture and Storage

CCS, also known as CO_2 sequestration, involves the cooling, separation, and capture of CO_2 emissions from flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible: carbon capture and compression, transport, and storage.

The first phase in CCS is to separate and capture the CO_2 gas from the exhaust stream, and then to compress the CO_2 to a supercritical condition.[118] Since most storage locations for CO_2 are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for CO_2, to inject CO_2 to those depths requires pressurizing the captured CO_2 to a supercritical state.

CO_2 capture can be performed via solvents or sorbents. The choice of the precise process varies with the properties of the exhaust stream. CO_2 separation has been demonstrated in the oil and gas industries, but the characteristics of those streams are very different from natural gas turbine system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which also has more highly concentrated CO_2 than exhaust from natural gas combustion. CO_2 capture technologies have not been demonstrated in the context of capturing CO_2 from combined cycle combustion turbines in full scale.

Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. To compress CO_2 to those levels, specialized technologies with high operating energy requirements are necessary. The CO_2 could be compressed to supercritical either before or after transport.

For phase two, CO_2 would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO_2 pipelines, particularly if supercritical CO_2 is being transported. Transport of CO_2 by pipeline is a demonstrated technology, but currently most CO_2 pipelines are in rural

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[116] U.S. EPA Environmental Appeals Board decision, *In re: City of Palmdale (Palmdale Hybrid Power Project)*. PSD Appeal No. 11-07, p. 727, decided September 17, 2012, citing .S. EPA Region 9, *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project* at 3 (Oct. 2011).

"Finally, we [EPA] note that the incorporation of the solar power generation into the BACT analysis for this facility [Palmdale] does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project."

[117] Such as the Ocotillo Plant EAB decision in September 2016, regarding pairing of battery storage with proposed new turbines. In that instance, the EAB denied the petition for review.

[118] Supercritical means that the CO_2 has properties of both a liquid and a gas. Supercritical CO_2 is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

areas. In addition, existing CO_2 pipeline networks are very limited and entirely absent in Georgia. Thus, transportation of CO2 for this project would require obtaining rights-of-way for pipelines to either connect to existing pipeline networks a number of states away or to an injection site in Georgia—none of which yet exist or have been reliably identified or demonstrated.

Various CO_2 storage methods have been proposed, though only geologic storage could be potentially achievable currently, depending on location. Geologic storage involves injecting CO_2 into deep subsurface formations for long-term storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO_2 could also potentially be used for enhanced oil recovery via injection into oil fields.

5.10.1.1.2 Efficient Turbine Design and Good Combustion, Operating, and Maintenance Practices

Efficient turbine design is inherent to the proposed project. The CCCT technology that will be used for the proposed Facility represents the latest evolution in technological advancements over previous designs. Among other things, the advancements associated with the proposed CCCT units include higher pressure ratios, increased firing temperatures, and advanced thermal barrier coatings. The proposed 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 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.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance and following an operations and maintenance (O&M) plan. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

5.10.1.2 Elimination of Technically Infeasible CO_2 Control Options – Turbine Systems (Step 2)

5.10.1.2.1 Carbon Capture and Storage

CCS involves cooling, separation, and capture of CO_2 from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

Carbon Capture

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[119] Currently, only two options appear to be potentially feasible for capture of CO_2 from the flue gas from the turbine systems: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-

[119] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[120] More recently, a report published by the Global CCS Institute in January 2025 indicated that "Standard industry models for carbon capture tend to use monoethanolamine (MEA) as a chemical solvent for the capture of CO2 from a flue gas stream."[121]

A review of the U.S. Department of Energy's (DoE) National Energy Laboratory's (NETL) research and development awards related to post-combustion capture of CO_2 indicates focus areas including CO_2 capture from various industries. Awards related to power generation from natural gas fired combined cycle combustion turbines remain limited to engineering scale testing and front-end engineering design studies.[122]

Although absorption technologies may be adaptable to flue gas streams of similar character to the flue gas from the turbine systems, the technology has never been commercially demonstrated for flue gas control in natural gas fired turbine operations.[123] The most recent NETL award (started December 2024) related to membrane technology was for an engineering-scale hybrid membrane-sorbent CO_2 capture system.

Even presuming carbon capture was technically feasible for the proposed operation, prior to sending the CO_2 stream to the appropriate storage site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[124] The auxiliary power load could be handled by installation of a separate system to solely support CO_2 compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an "energy penalty" for operation of the CO_2 compression system.

Because carbon capture is not demonstrated as described above, CCS is not technically feasible.

Carbon Transport

The next step in CCS is the transport of the captured and compressed CO_2 to a suitable location for storage. This would typically be via pipeline. Depending on location, pipeline transport is an available and demonstrated, although costly, technology. The existing pipeline network is limited to fractured sections in Mississippi, Louisiana, Texas, North Dakota, and a few states in the Mountain West. These pipelines are unavailable to the project for geographic reasons.

Since there are no CO_2 pipelines in the area, OPC would need to construct a CO_2 pipeline to a storage location a number of states away or to a unidentified and undeveloped viable storage location in Georgia—if

[120] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[121] Barlow, Shahi, Kearns, Advancements in CCS Technologies and Costs, January 2025, page 12. https://www.globalccsinstitute.com/wp-content/uploads/2025/01/Advancements-in-CCS-Technologies-and-Costs-Report-2025.pdf

[122] Website reviewed March 2025: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[123] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for GHG emissions, Attachment B page 62.

[124] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

any—if it were to pursue carbon sequestration as a CO_2 control option.[125] While CO_2 pipelines may be constructable under some circumstances, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline could be built from the Facility to a potential carbon storage location; however, this conservative assumption is unrealistic because no viable storage locations have been identified and developed in Georgia, let along in close proximity to the Facility. Realistically, a longer pipeline would be required, and with increasing length, land use and right-of-way considerations become increasingly problematic. Because carbon capture is not demonstrated as described above, CCS is not technically feasible.

Carbon Storage

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and could be captured, separated, and then re-injected. At the end of EOR, the CO_2 remaining in the subsurface would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rock.
- Un-Mineable Coal Seams: Additional storage is possible by injecting CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional theoretical methods of sequestration such as direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not documented in the literature for industrial scale applications. As such, while capture and transport are both infeasible, the most limiting factor for CCS at the Facility may be the absence of a mechanism for permanent storage of the captured CO_2.

NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[126] According to the database, the Paluxy Formation in Citronelle, Alabama is the closest sequestration site where CO_2 has the potential to be stored in the future. The Citronelle Project was a demonstration-scale Southeast Regional Carbon Sequestration Partnership (SECARB) CO_2 sequestration project site focused on coal-fired power plant emissions. The project operated for just over two years and ceased operating in 2014 due to repeated injection well failures.[127] While the project is reported to have achieved injection of limited

[125] *A Review of the CO_2 Pipeline Infrastructure in the U.S.*, National Energy Technology Laboratory, Office of Fossil Energy, U.S. Department of Energy, April 2015. DOE/NETL-2014/1681. https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

[126] Carbon Capture and Storage Database maintained by the NETL, accessed November 2024 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[127] *Final Project Report – SECARB Phase III,* SECARB. Report at https://www.osti.gov/servlets/purl/1823250

amount of CO_2 (less than 115,000 metric tons), that is a small fraction of the CO_2 expected to be emitted by the Facility each year.[128] The injection location is a saline reservoir within the Citronelle Oilfield in Mobile County, Alabama, located approximately 12 miles from the CO_2 source—Alabama Power's *coal*-fired Plant Barry. Based on a review of the NETL database, Citronelle, Alabama is the closest CO_2 sequestration project site (pilot or large-scale) to the Facility and is approximately 288 miles from the proposed Facility.

OPC has concluded that CCS technology is not technically feasible at this time and is eliminated from further consideration as BACT, based on the discussions provided. In fact, the infeasibility of CCS in this instance is sufficiently significant that implementing CCS in connection with the Facility would also impermissibly redefine the source—converting a discrete combined-cycle natural gas-fired power plant to an operation likely spanning multiple states and incurring CCS related costs likely so significant that the Facility's basic business purpose would be disrupted away from power production and to CCS experimentation.

Additionally, for the recent final rule, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units*, U.S. EPA concluded that the use of CCS was not practicable at this time for any combined cycle combustion turbines. Even as to base load units, EPA concluded that CCS could not be considered the best system of emissions reduction (BSER) for at least eight years from the proposal date:[129]

> *The BSER for base load combustion turbines contains two components and the EPA is promulgating standards of performance to be implemented in two phases with each phase reflecting the degree of emission reduction achievable through the application of each component of the BSER . . . The phase 2 standard of performance for base load combustion turbines reflects the implementation of 90 percent capture CCS on a highly efficient combined cycle combustion turbine system.* ***The compliance date begins January 1, 2032.***

At present, no combined cycle combustion turbines employ CCS at scale in the U.S. In order for EPA to attempt to justify that CCS might be "adequately demonstrated," EPA built in an 8-year lead time before an applicable standard would restrict emissions based on a presumed CCS-level of control. As such, CCS-level of control is not currently required under an applicable standard, and EPA concluded that CCS is not available within the time frame that the Facility is expected to commence operation. (Furthermore, EPA's approach to building in an 8-year lead time into the NSPS emission limit to attempt to engineer adequate demonstration is controversial and is currently subject to legal challenge and reconsideration by EPA, and OPC disagrees with EPA's rulemaking.) Thus, because the PSD BACT limit must be achievable upon startup of the Facility, EPA's rulemaking purporting to require CCS in eight (8) years effectively confirms the analysis in this application, which shows that CCS is not technically feasible, available, or demonstrated at this time.

Despite the significant technical challenges discussed earlier in implementing CCS technology on turbine systems of this size and in the location of this project, OPC is including CCS in Step 4 of this analysis for the sake of discussion, despite having concluded that CCS cannot be considered BACT because CCS is technically infeasible and would redefine the source.

[128] *Final Project Report – SECARB Phase III,* SECARB. Report at https://www.osti.gov/servlets/purl/1823250

[129] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; 89 FR 39798, May 9, 2024

5.10.1.2.2 Efficient Turbine Design and Good Combustion, Operating, and Maintenance Practices

One way to efficiently generate electricity from a natural gas fuel source for appropriate load goals is the use of a combined cycle turbine design as is the case for the proposed units. Efficient turbine design coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

Therefore, efficient turbine design coupled with good combustion, operating, and maintenance practices are evaluated further for CO_2 BACT purposes. In addition, although infeasible, CCS is further evaluated in Step 4, which demonstrates that CCS would also be precluded from being selected BACT based on consideration of its energy, environmental, and/or economic impacts.

5.10.1.3 Summary and Ranking of Remaining CO_2 Controls (Step 3)

As detailed in Step 2, the only feasible control option is efficient turbine design and good combustion, operating, and maintenance practices. As a technically feasible control option, it is evaluated further in the BACT process. In addition, although infeasible, CCS is further evaluated in Step 4, which demonstrates that CCS would also be precluded from being selected BACT based on consideration of its energy, environmental, and/or economic impacts.

5.10.1.4 Evaluation of CO_2 Control Technologies (Step 4)

5.10.1.4.1 Carbon Capture and Storage

As noted above, CCS is infeasible and cannot be considered BACT for that reason alone. In addition, for the reasons outlined in this section, this option cannot be selected as BACT due to cost-effectiveness considerations.

The use of CCS would be prohibitive to the proposed project. The costs associated with the system include capital costs, such as the installation of a pipeline for conveyance and the actual installation of the capture and compression system, and the costs associated with identification, installation, operation and maintenance of carbon capture, transport, and storage. Detailed cost calculations are provided in Appendix C, with a brief summary herein.

The first capital cost for consideration is the cost associated with the installation of a pipeline from the Facility site to the nearest carbon sequestration site. Currently, there exists no carbon storage sites in the State of Georgia, and the site closest potentially viable to the Facility is the Citronelle Oilfield in Mobile County, Alabama. However, this site is not operating and ceased operating after two years due to repeated injection well failures and after injecting less than 115,000 tonnes of CO_2; consequently, using even the Citronelle Oilfield for pipeline capital costs is unrealistically optimistic. Nevertheless, if the shortest possible pipeline between these sites were to be installed, 288 miles of pipeline would be installed, crossing from Georgia into Alabama.[130] In addition, at least one injection well will need to be installed at the site. Costs

[130] Distance from the facility to Citronelle Oilfield, conservatively assumes the shortest distance as the pipeline route.