Facility Name:	**Chattahoochee Energy Facility**
City:	Franklin
County:	Heard
AIRS #:	04-13-149-00006

Application #:	TV-634172
Date Application Received:	April 4, 2022
Permit No:	4911-149-0006-V-06-0

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Introduction

This narrative is being provided to assist the reader in understanding the content of referenced operating permit. Complex issues and unusual items are explained here in simpler terms and/or greater detail than is sometimes possible in the actual permit. The permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description

A. Facility Identification

1. Facility Name

   Chattahoochee Energy Facility (CEF)

2. Parent/Holding Company Name

   Oglethorpe Power Corporation (OPC)

3. Previous and/or Other Name(s)

   Wansley Combined Cycle Energy Facility (WCCEF)

4. Facility Location

   3461 Hollingsworth Ferry Road
   Franklin, Georgia 30217

5. Attainment, Non-attainment Area Location, or Contributing Area

   Chattahoochee Energy Facility (hereinafter "facility") is located in Heard County, which is in attainment for ozone but designated as a contributing county with enhanced monitoring.

B. Site Determination

Wansley Steam-Electric Generating Plant (AFS No. 149-00001), Southern Power - Wansley Combined-Cycle Generating Plant (AFS No. 149-00011), Oglethorpe Power Corporation – Chattahoochee Energy Facility (AFS No. 149-00006), and Municipal Electric Authority of Georgia – Wansley Unit 9 (AFS No. 149-00007) are permitted separately. Collectively, they comprise the same Title V site. However, each separate owner/operator is only accountable, for compliance purposes, for the individual electrical generating units that they own or operate.

C. Existing Permits

Table 1 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a comparative review of form A.6, Current Permits, of the Title V application and the "Permit" file(s) on the facility found in the Air Branch office.

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

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-149-0006-V-05-0	January 30, 2018	Title V Renewal
4911-149-0006-V-05-1	December 30, 2020	The CT Upgrades Project involved modifications to the facility's combustion turbines. The project resulted in increases in maximum heat input and maximum projected annual air emissions.
4911-149-0006-V-05-2	December 6, 2022	Acid Rain Permit Renewal

D. Process Description

1. SIC Codes(s)

   4911

   The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

   Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

   Chattahoochee Energy Facility burns natural gas to generate electricity for downstream users.

3. Overall Facility Process Description

   Chattahoochee Energy Facility includes one combustion turbine combined-cycle block that includes two combustion turbines with a supplementally fired heat recovery steam generator (HRSG) and one steam turbine. The combined-cycle blocks fire only natural gas. Each combustion turbine is equipped with an evaporative inlet cooler and lube oil demister vents. Ancillary equipment includes one cooling tower.

OPC requested that the permitted equipment be the Siemens Westinghouse (SW) model V84.3a2. The nominal power rating of the SW V84.3a2 is 167 MW. The duct burners are rated at 95 MMBtu/hr each. The facility produces 334 MW from the combustion turbines and approximately 187 MW from the steam turbine for a nominal power block total of 521 MW.

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In this permitting action, OPC (Oglethorpe Power Corporation) proposed the CT (combustion turbine) Upgrades Project involving modifications to the facility's combustion turbines. The project resulted in increases in maximum heat input and maximum projected annual air emissions.

The proposed CT Upgrades Project involved the implementation of two upgrades for OPC Chattahoochee’s two combustion turbines: the Thermal Performance Upgrade One (TPU1) and the Low Load Turndown (LLTD) upgrade.

The TPU1 improved the combustion turbines plant output and heat rate as well as extended the maintenance interval of the units by installing enhanced hardware in the combustion turbines, replacing certain auxiliary hardware components, and adding site-specific control logic optimizations.

New turbine hardware included combustion chamber components with optimized cooling air reduction, impingement cooled tile holders, the latest ceramic heat shields, metallic heat shields, and burner swirlers with reduced swirl angle. Auxiliary hardware replacements included the pilot gas flow meter, an advanced combustion dynamics monitoring system, heat resistant ignition cables, blow-off valve actuators, and additional pressure and acceleration measurement instrumentation. These changes increased the capacity of the facility by approximately 23 MW, with variations for ambient temperatures. The increased capacity decreased the cost of electricity generation.

The LLTD upgrade involved the installation of new combustion turbine components and software controls to replace selected equipment and connected accessories to allow for sustained operations at lower operating loads during periods of low demand.

These changes included the compressor inlet guide vane extended range sensor, ring modification and linearization unit replacement, and the addition of a combustion turbine exhaust metallic heat shield, along with site-specific control logic optimizations. Currently, the facility shuts down periodically during low demand and then restarts when demand increases. The LLTD upgrades allowed the combustion turbines to operate at steady-state minimum loads of approximately 67 MW, with variations for ambient temperatures, while continuing to maintain emission concentrations of NO_X and CO in compliance with the facility’s permitted emission limits. As a result, this upgrade allowed the facility to continue to operate with less frequent shutdowns during low demand periods, thereby reducing maintenance and fuel costs associated with cycling through shutdowns and startups.

Since CEF is a major source under the PSD permitting program, emission increases from the proposed project were evaluated and compared to the significant emission rates (SERs) for regulated pollutants under the PSD program. OPC has evaluated emissions increases of CO, NO_X, particulate matter (PM), total particulate matter with an aerodynamic diameter of less than 10 microns (PM_{10}), total particulate matter with an aerodynamic diameter of less than 2.5 microns ($PM_{2.5}$), greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and VOC resulting from the proposed project for comparison to their respective PSD SERs to determine whether PSD permitting is required, as shown in **Error! Reference source not found.**2.[1] As illustrated in Table 2, the project emissions increases do not exceed the SERs for any pollutant. Accordingly, neither PSD nor NNSR review is required. Detailed emission calculations can be found in Appendix B of the application.

Table 2: Project Emissions Increases

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	**36.7**	40	No
CO	19.0	30.0	67.6	37.6	-	**37.6**	100	No
VOC	11.6	13.5	15.1	1.59	-	**1.6**	40	No
PM	69.7	81.1	90.6	9.5	0.31	**9.8**	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	**9.8**	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	**9.5**	10	No
SO_2	7.0	8.1	9.1	0.95	-	**0.9**	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	**0.1**	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	**188,361**	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

For purposes of calculating project emissions increases, different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether the sources affected by the proposed project are considered new or existing emission units. Federal rules, 40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units and are incorporated by reference in the GRAQC.

As the emission units at CEF have operated for more than two years, the proposed project involved physical or operational changes to existing emission units only – specifically, the facility's combustion turbines. There were no new emission units proposed for installation as part of this project.

[1] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, lists the lead (Pb) emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed project were not evaluated.

Baseline Actual Emissions

The most recent 5-year lookback period was utilized for this analysis. Accordingly, the period of May 2016 to April 2018 was selected as the 2-year (consecutive 24-month) baseline period for all pollutants except for CO, for which the period of August 2015 to July 2017 was selected. Baseline actual emissions data utilized for the NSR analysis for each combined cycle combustion unit can be found in Appendix B of the application.

At the time of application submittal, OPC expected to begin construction of the CEF Upgrades Project on or before December 31, 2022. The selected baseline data are representative of normal operation. Because the representativeness of future (2021-2022) emissions was unknown and could be impacted by factors outside of OPC's control (e.g., fluctuations in fuel prices), the selected baseline data were approved by the Division under GRAQC 391-3-1-.02(7)(a)2.(i)(I) provided that construction of the CT Upgrades Project begins on or before December 31, 2022. Per the new Conditions in 7.14 of Permit Amendment No. 4911-149-0006-V-05-1, in order to begin construction after December 31, 2022, OPC would have first been required to update the PSD applicability test and submit such information to EPD. Construction activities for the CT Upgrades Project were completed in 2022, and initial operation of the units following completion of construction occurred December 27 and 28, 2022.

Projected Actual Emissions

Projected actual emissions for the modified equipment were determined for use in the NSR analysis, based on the highest projected level of actual annual utilization of the modified combustion turbine systems in the ten years following the project (at 30.2 x 10^6 MMBtu/yr total for both CCCTs), and estimated actual emission factors derived from facility operations, as summarized in

Table 3.

Table 3. Criteria Pollutant Projected Actual Emission Factors for CCCT Units

Pollutant	Emission Factor (lb/MMBtu)
VOC[1]	1.00E-03
$PM_{10}/PM_{2.5}$[2]	6.00E-03
SO_2[3]	6.00E-04
NO_X[4]	1.01E-02
CO[4]	4.48E-03
H_2SO_4[5]	6.89E-05
CO_2[6]	118.86
CH_4[7]	2.20E-03
N_2O[7]	2.20E-04
CO_2e[7]	118.98

1. VOC emissions were based on the most recent facility compliance testing data. The total VOC emission factor was calculated as the sum of the 2005 VOC as CH_4 (Method 25A) test results and the 2003 formaldehyde (Method 0011) test results. A 10% safety factor was conservatively applied to the stack test results. The emissions concentrations (ppm @ 15% O_2) were converted to emission factors (lb/MMBtu) using the following equation:

$$lb/MMBtu = (C_{gas,\ VOC\ as\ CH4} * MW_{VOC\ as\ CH4} + C_{gas,\ HCHO} * MW_{HCHO}) * Fd * 2.59E\text{-}9 * 20.9 / (20.9 - \%O_2)$$

where:

$C_{gas,\ VOC\ as\ CH4}$ =	0.596	ppmv, maximum VOC as CH_4 test result for either unit at any load
$MW_{VOC\ as\ CH4}$ =	16.043	lb/lb-mol, molecular weight of CH_4
$C_{gas,\ HCHO}$ =	0.061	ppmv, maximum HCHO test result for either unit at any load
MW_{HCHO} =	30.026	lb/lb-mol, molecular weight of HCHO
Fd =	8,710	dscf/MMBtu, natural gas fuel factor from 40 CFR 60, Method 19, Table 19-2
$\%O_2$ =	15	%, corrected basis for exhaust gas O_2 content

2. PM emissions are based on the average of the 2003 compliance testing results for units 8A (0.0069 lb/MMBtu) and 8B (0.0051 lb/MMBtu). The 2003 testing was inclusive of both the filterable and condensable portions of PM. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5} = PM_{10} = PM$).

3. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

4. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

4. The projected actual NO_X and CO emission rates were conservatively based on the maximum of the monthly average emission rates (monthly emissions divided by monthly heat input) during the 24-month baseline period for each pollutant.

5. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

6. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

7. CO_2e was calculated as the sum of the emission factor for each GHG pollutant multiplied by that pollutant's global warming potential (GWP). GWPs were taken from 40 CFR 98, Subpart A, Table A-1:

CO_2:	1
CH_4:	25
N_2O:	298

CCTT HAP Emission Factors

HAP and toxic air pollutant (TAP) emissions are evaluated from each CCCT using AP-42 based emission factors and vendor based information, as appropriate. Details regarding the estimation of HAP/TAP emissions can be found in Appendix C of the application.

Cooling Tower Emission Factors

Cooling tower emissions, as found in Appendix B of the application, are calculated based on a vendor based drift rate, and facility records of the Total Dissolved Solids (TDS) concentration present in the waters processed at the cooling tower. This data is relied upon using emission estimation methods for cooling towers outlined in *Calculating Realistic PM_{10} Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002, to estimate potential emissions from the facility cooling towers.

Insignificant Emission Sources

The facility has other small insignificant sources of emissions (e.g., fugitive piping leaks, roads, etc.) at the facility which are not quantified within the potential to emit estimates within the application.

Could Have Accommodated Emissions

The "could have accommodated" emissions for this project are based on consideration of the "Georgia Pacific memo" and subsequent correspondence with U.S. EPA, indicating that a maximum 30-day period can be utilized to demonstrate emissions that "could have been accommodated" by a source during the respective baseline period.[2] Additional conservative assumptions were applied to the 30-day maximum period technique as outlined in the referenced Georgia Pacific memo.

Specifically, application of an additional seasonal variation was relied upon for this analysis. The maximum 30-day period from each season was evaluated and used to evaluate total emissions for the entire seasonal period. Seasonal breakdowns were evaluated as follows;

Spring: March – May
Summer: June – August
Fall: September – November
Winter: December – February

Emissions that were excluded using this methodology are necessarily unrelated to the proposed project as they are based on existing capacity and actual data from the selected baseline period.

[2] https://www.epa.gov/nsr/response-georgia-pacific-use-demand-growth-exclusion-projected-actual-emissions

Additional data regarding the "could have been accommodated" analysis is included in Appendix B of the application.

Associated Emissions Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases. CEF anticipates that the modifications to and increased utilization of the combustion turbines would result in an associated increase in drift loss and, therefore, air emissions from the facility's cooling tower. As such, an associated emissions increases are included in this analysis for the cooling towers.

Toxic Impact Analysis

A toxic impact analysis was performed and included in the application in Appendix C. The Division reviewed the analysis and agrees that the result of the analysis is that the impacts of all TAP from CEF are well below the respective annual, 24-hour, and 15-minute AACs.

4. Overall Process Flow Diagram

The facility provided a process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

The facility is located in Heard County, which is in attainment for ozone but designated as a contributing county with enhanced monitoring. The combined site is one of the 28 PSD named source category (fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input). Since it has potential emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxide (NOx), volatile organic compounds (VOC), and carbon monoxide (CO) greater than 100 tpy, it is a major source under PSD regulations.

The facility went through a PSD review for NOx, SO_2, CO, VOC and PM/PM_{10} in August 2001 for the construction and operation of the combustion turbine combined-cycle block. Conditions 3.3.1 through 3.3.10 of Title V Permit No. 4911-149-0006-V-06-0 contains all the BACT standards resulting from that PSD review.

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The facility is an existing PSD major source, as it has potential emissions of multiple regulated criteria pollutants exceeding the major source threshold of 100 tpy.[3] As a result, new construction or modifications that result in emissions increases for criteria pollutants are potentially subject to PSD permitting requirements.

Additionally, the facility is located in a county specified by the Division as subject to GRAQC 391-3-1-.03(8)(c)15, which addresses additional provisions for electrical generating units in the areas contributing to the Atlanta ozone nonattainment area. This state regulation specifies that certain NNSR provisions are potentially applicable when permitting new construction or modifications at any electrical generating unit that is located in a listed contributing county and

[3]Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input (which includes combined cycle natural gas plants) are on the "List of 28" named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy.

that has facility-wide potential NO_X emissions exceeding 100 tpy.[4] As the CEF's potential NO_X emissions exceed 100 tpy, the facility is a major source for NO_X emissions under this state regulation. Therefore, applicability of the proposed project to these NNSR permitting provisions was assessed.

As the facility is classified as a major source for PSD, if the proposed project meets the definition of a *major modification*, then the full PSD permitting requirements apply. For all PSD-regulated pollutants other than CO_2e, PSD permitting is required if the emissions increase of a specific pollutant exceeds that pollutant's PSD SER. For CO_2e, PSD permitting is only required if the emissions increase exceeds the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant.[5] For NO_X, certain NNSR provisions are required if the emissions increase exceeds the applicable NNSR SER of 40 tpy.[6] As illustrated in Table 2, the project emissions increases do not exceed the SERs for any pollutant. Accordingly, neither PSD nor NNSR review is required.

2. Title V Major Source Status by Pollutant

Table 4: Title V Major Source Status

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

[4] GRAQC 391-3-1-.03(8)(c)15(i)

[5] 40 CFR 52.21(b)(49)(iii) as incorporated by reference in the GRAQC

[6] GRAQC 391-3-1-.03(8)(c)15(ii)

3. MACT Standards

Since the combined site is major under Title V of 1990 CAAA for single and combined HAP, the facility is subject to 40 CFR 63 Subpart YYYY – "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

4. Program Applicability (AIRS Program Codes)

Program Code	Applicable (y/n)
Program Code 6 - PSD	Yes
Program Code 8 – Part 61 NESHAP	No
Program Code 9 - NSPS	Yes
Program Code M – Part 63 NESHAP	Yes
Program Code V – Title V	Yes

Regulatory Analysis

II. Facility Wide Requirements

A. Emission and Operating Caps:

None applicable.

B. Applicable Rules and Regulations

None applicable.

C. Compliance Status

None applicable.

D. Permit Conditions

None applicable.

III. Regulated Equipment Requirements

A. Equipment List for the Process

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	Description		ID No.	Description
CT8A	Combustion Turbine Unit 8A Siemens-Westinghouse Model V84.3a2 Capacity = 177 MW (ISO) Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60, Subpart KKKK 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY Acid Rain CSAPR 391-3-1-.02(2)(b)1. 391-3-1-.02(2)(g)2.	LC8A SC8A	Dry Low NOx Burner SCR Catalytic Oxidation**
DB8A	HRSG Duct Burner for Turbine 8A Capacity = 95 MMBtu/hr Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart KKKK Acid Rain 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)2.	LD8A SC8A	Dry Low NOx Burner SCR Catalytic Oxidation**
CT8B	Combustion Turbine Unit 8B Siemens-Westinghouse Model V84.3a2 Capacity = 177 MW (ISO) Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60, Subpart KKKK 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY Acid Rain CSAPR 391-3-1-.02(2)(b)1. 391-3-1-.02(2)(g)2.	LC8B SC8B	Dry Low NOx Burner SCR Catalytic Oxidation**
DB8B	HRSG Duct Burner for Turbine 8B Capacity = 95 MMBtu/hr Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart KKKK Acid Rain 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)2.	LD8B SC8B	Dry Low NOx Burner SCR Catalytic Oxidation**

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards are intended as a compliance tool and may not be definitive.

** Catalytic Oxidation System was not required as a result of CO BACT review done in August 2001.

B. Equipment & Rule Applicability

Emission and Operating Caps:

The emission and operating caps in Section 3.3 of the permit are all related to the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS), and National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations. They are explained in detail in the following section.

Rules and Regulations Assessment:

The 2001 PSD Review and Resulting BACT Limits

The power block (known as Power Block 8) which includes Combustion Turbines CT8A/CT8B, and Duct Burners, DB8A/DB8B, were originally permitted by the previous owner (Georgia Power) as part of a project that involved the construction and operation of four (4) combined-cycle blocks at their existing Wansley Steam-Electric Generating Plant in Roopville, Heard County, Georgia. This project underwent PSD review. The resulting PSD Permit, No. 4911-149-0006-V-01-0, was issued on January 15, 2002. The following is a summary of the resulting BACT determination for NOx, CO, VOC, SO_2, and PM/PM_{10}.

NOx

EPD has determined that the proposal to use a dry low NOx (DLN) combustor in the turbine and a DLN burner in the duct burner with SCR as post-combustion control for the turbine and duct burner while burning natural gas meets the requirements of best available control technology (BACT). The NOx BACT emission limit is set at 3.0 ppmvd (corrected to 15% oxygen) at the stack exit for the CT/HRSG system. The averaging period is on a rolling 4-hour basis.

NOx emissions from the combined-cycle block are capped to not equal or exceed 179.6 tons per year. No limit is required on heat input since the BACT analysis was at 8,760 hours per year.

Sulfur Dioxide

The Division has determined that the facility's s proposal to only fire natural gas in the CT/HRSG systems meets the requirements of BACT for SO_2.

Carbon Monoxide and Volatile Organic Compounds

The Division has determined that the facility's proposal to use proper combustion design meets the requirements of BACT. CO and VOC emissions have to be balanced against NOx emissions. At the proposed BACT emissions levels for NOx, the CO and VOC emissions will be limited to the following at the combined stack exit:

CO = 2.0 ppm@15% oxygen
VOC = 2.0 ppmvd (as methane) @ 15% oxygen

Particulate Matter

The Division has determined that the burning of clean fuels in the combustion turbines meets the requirements of BACT. PM emissions, and thus PM_{10} emissions, will be limited to the BACT PM limits proposed by the company.

Summary

Emission Standards: The 2001 PSD review has illustrated the analysis performed to assess the appropriate BACT for the proposed CT/HRSG system. The results are summarized in the following table:

Pollutant	BACT - CT Exit	BACT - DB Exit	Combined or Stack Exit (Permit Limit)	Averaging Period
NOx	DLN Combustor	Low-NOx Burner	Controlled by SCR	
			3.0 ppmvd @ 15% O_2	4-hour rolling average
			179.6 tpy / block	Annual limit
CO	Efficient Combustion	Efficient Combustion	2.0 ppmvd @ 15% O_2	3-hour rolling average
			86 tpy / block	Annual limit
VOC	Efficient Combustion	Efficient Combustion	2.0 ppmvd @ 15% O_2 as methane	Based on applicable test method.
SO_2	Fire natural gas only	Fire natural gas only	Fire natural gas only	N/A
PM/PM_{10}	Fire natural gas only Efficient Combustion	Fire natural gas only Efficient Combustion	0.011 lb/MMBtu	Based on applicable test method.
			10% opacity	6-minute average

The above BACT limits are included in Conditions 3.3.1 through 3.3.10 of the Title V renewal permit.

Federal Regulation Standards

Combustion Turbines CT8A and CT8B

40 CFR 60 Subpart GG – "Standards of Performance for Stationary Gas Turbines"

40 CFR 60 Subpart GG is an applicable requirement for each CT because each CT has a nameplate capacity greater than 10 MMBtu/hr, and they are constructed after October 3, 1977. The combustion turbines were previously subject to NSPS GG prior to the completion of the CT Upgrades Project.

Since the completion of the CT (combustion turbine) Upgrades Project, the combustion turbine systems are now 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. Therefore, NSPS Subpart GG no longer applies to the facility's combustion turbines following the project completion.

40 CFR 60 Subpart KKKK – Stationary Combustion Turbines

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.[7] CEF consists of two natural gas-fired turbines, each of which was constructed prior to 2005 and has a heat input capacity exceeding 10 MMBtu/hr. To determine if the turbines became subject to NSPS Subpart KKKK following the project, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as:[8]

…any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

More specifically, for an existing electric utility steam generating unit:[9]

No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification…provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

The CT Upgrades Project resulted in an increase in the hourly heat input capacity for the combustion turbines. OPC has presumed that an increase in the amount of an air pollutant regulated by NSPS Subpart KKKK could occur on a short-term (hourly) basis. Therefore, the CEF combustion turbines are now subject to NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(a), the associated HRSG and duct burners are also subject to NSPS Subpart KKKK.

Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. HRSGs and duct burners regulated under NSPS Subpart KKKK are also exempt from the requirements of NSPS Subparts Da, Db, and Dc.

Emission Limits

Per Table 1 to NSPS Subpart KKKK, a modified combustion turbine is subject to NO_X emission limits depending on the type of fuel combusted and the heat input at peak load. For modified 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. NSPS Subpart KKKK also includes, for units greater than 30 MW output, a NO_X limit of 96 ppm at 15% O_2 or

[7] 40 CFR 60.4305(a), (b)

[8] 40 CFR 60.2

[9] 40 CFR 60.14(h)

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.[10] Compliance with the NO_X emission limit is determined on a 30 unit operating day rolling average basis.[11] The combustion turbines and duct burners are presently subject to a NO_X BACT limitation of 3.0 ppm at 15% O_2, 4-hour average per Condition 3.3.6.a of the existing Title V operating permit.

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.[12]

<u>Monitoring and Testing Requirements</u>

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

<u>NO_X Compliance Demonstration Requirements</u>

The combustion turbine systems presently employ a continuous emission monitoring system (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Pursuant to 40 CFR 60.4340(b)(1) and 40 CFR 60.4345, CEF can rely on its existing NO_X CEMS installed and certified according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS Subpart KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[13] Initial compliance with the NO_X emission limit was demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR 60.4405 to the NO_X emission limit under this subpart.[14] NO_x emissions must be measured after the duct burner rather than directly after the turbine.

<u>SO_2 Compliance Demonstration Requirements</u>

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by the Division;[15] however, CEF elects to opt out of this provision of the

[10] Table 1 to Subpart KKKK of Part 60

[11] 40 CFR 60.4350(h), 40 CFR 60.4380(b)(1)

[12] 40 CFR 60.4330(a)(1) or (a)(2), respectively

[13] 40 CFR 60.4340(b), 40 CFR 60.4405

[14] 40 CFR 60.4405(c)

[15] 40 CFR 60.4370(b) and (c)

rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[16] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and results in potential emissions not exceeding 0.060 lb/MMBtu; or

- 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 0.060 lb SO_2/MMBtu heat input.

CEF is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines and duct burners through submittal of a semiannual analysis of the gas by the supplier or the facility to demonstrate that the sulfur content does not exceed its excursion threshold of 0.27 grains per 100 standard cubic feet.[17] This sulfur content analysis by the supplier or CEF satisfies the sulfur content demonstration requirement of 40 CFR 60.4365. Therefore, continued compliance with this existing permit condition will guarantee compliance with the NSPS Subpart KKKK sulfur monitoring requirement.

Initial Notification

Per 40 CFR 60.7(a)(4), Permit Application No. TV-486572 serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units,* applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 18, 2014, and to any steam generating unit or IGCC modified after June 18, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[18] The existing CCCT generating units for CEF each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, the CCCT generating units (including the duct burners) could potentially be subject to the provisions of NSPS TTTT.

With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after the specified dates, not modification. “Reconstruction” is defined under 40 CFR 60 Subpart A as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable

[16] 40 CFR 60.4365

[17] Permit No. 4911-149-0006-V-05-0, Conditions 5.2.3, 5.2.4, 6.1.7.c.i.

[18] 40 CFR 60.5509(a)

standards.[19] The total cost of the TPU1 and LLTD upgrades is well under 50% of the cost for two comparable new units. As the combustion turbines at CEF are existing units and the project did not meet the reconstruction definition, the modifications to the turbine systems did not trigger applicability of NSPS Subpart TTTT requirements.[20]

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

The combustion turbines are also subject to 40 CFR 63 Subpart YYYY, per 40 CFR 63.6085(a) and (b), because the turbines are located a major source (the combined site) of single and combined HAP emissions. Per 40 CFR 63.6090(a)(1), both of Combustion Turbines CT8A and CT8B are existing affected sources. According to 40 CFR 63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part.

Reconstruction for the purposes of the NESHAP in 40 CFR 63 is defined as:[21]

The replacement of components of an affected or a previously nonaffected source to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source;

The proposed CT Upgrades Project did not exceed more than 50% of the cost of two comparable new combustion turbines. Therefore, the combustion turbines at CEF remain existing sources under Subpart YYYY following the proposed project.

Initial Notification

No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

40 CFR 64, Compliance Assurance Monitoring (CAM)

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), facilities are required to prepare and submit monitoring plans for certain emissions units as part of Title V operating permit applications. The CAM plans are intended to provide an on-going and reasonable assurance of compliance with emission limits for units equipped with air pollution control devices. Pursuant to 40 CFR 64.2(b)(1)(vi), emission limits for which a Part 70 Permit specifies a continuous compliance determination method are exempt from CAM requirements. Since Condition 5.2.1 of the facility's permit requires the operation of a NO_X and CO CEMS for both CCCT stacks, the Division has previously determined that the emission units are exempt from CAM. Therefore, no CAM documentation was included with the permit application.

[19] 40 CFR 60.15

[20] 40 CFR 60.5509(a)

[21] 40 CFR 63.2

The combustion turbines (ID Nos. CT8A and CT8B) and duct burners (ID Nos. DB8A and DB8B) are controlled by the selective catalytic reduction (SCR) to control NOx emissions in order to comply with the NOx BACT limit. Although the combustion turbines and duct burners are controlled by a catalytic oxidation system to reduce CO emissions, the catalytic oxidation system was not required as the CO BACT in the 2001 PSD review.

Federal Rule – Acid Rain Program

Applicability: The Acid Rain Regulations apply to the CT/HRSG system because it has a nameplate capacity greater than $25MW_e$ and it is to supply electricity for sale, whether wholesale or retail.

This facility is subject to requirements in Title IV of the 1990 Clean Air Act Amendment (CAAA). The CT/HRSG system is subject to 40 CFR 72 (permits), 73 (sulfur dioxide), and 75 (monitoring). It is not subject to the nitrogen oxide provisions (40 CFR 76) of the Acid Rain regulations because it does not have the capability to burn coal.

Emission Standard: No SO_2 allowances are allocated up front to the facility, by the Acid Rain Regulations. As such, OPC will need to acquire SO_2 allowances in amounts equal to their annual SO_2 tonnage. Annual SO_2 emissions could be as high as 10.7 tpy for Power Block 8.

NOx emissions are not limited by the Acid Rain Regulation since the units are not classified as coal-fired utility boilers.

Federal Rule – Cross-State Air Pollution Rule (CSAPR)

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X emissions by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NOX Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions. Following legal challenges, CSAPR replaced CAIR and began Phase 1 implementation on January 1, 2015 for annual programs and May 1, 2015 for the ozone season program. Phase 2 implementation began on January 1, 2017 for annual programs and May 1, 2017 for ozone season programs.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). Georgia is subject to CSAPR programs for both fine particles (SO2 and annual NOX) and ozone (ozone season NOX).

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402. In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. OPC Chattahoochee's

CCCTs are affected sources under this regulation, and the proposed project will not alter any applicable requirements or compliance options of CSAPR to the facility's operations. OPC Chattahoochee will continue to maintain sufficient allowances under CSAPR for its operations.

Duct Burners DB8A and DB8B

Federal Rule Standards

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

Presently, the Duct Burners DB8A and DB8B at CEF are subject to NSPS Subpart Dc. They were constructed after June 9, 1989; and each has a maximum design heat input rate between 10 and 100 MMBtu/hr (95 MMBTU/hr), However, upon completion of the proposed modifications, the combustion turbine systems will be subject to NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(a), "Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners." Under 40 CFR 60.4305(b), "Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part."

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

Since the combined site is major under Title V of 1990 CAAA for single and combined HAP emissions, the duct burners could potentially be subject to 40 CFR 63 Subpart DDDDD. However, duct burners meet the definition of a waste heat boiler, which is excluded from the definition of a boiler. Since the duct burners are not boilers, they are not subject to 40 CFR 63 Subpart DDDDD.

The rule defines a "boiler" as an enclosed device using controlled combustion to recover thermal energy in the form of steam and/or hot water. The combustion turbines at the OPC Chattahoochee use the thermal energy of natural gas directly through combustion and without use of steam or hot water. Therefore, they do not fall within the definition of a "boiler" and are not subject to the rule.

GA State Rule Standards

Combustion Turbines CT8A and CT8B

The combustion turbines are subject to the visible emission limit (40 percent opacity) specified in Georgia Air Quality Control Rule 391-3-1-.02(2)(b) "Visible Emissions," and the fuel sulfur content limit specified in Georgia Air Quality Control Rule 391-3-1-.02(2)(g) "Sulfur Dioxide." Note that the GA Rule (b) visible emission limit is subsumed by the PM BACT limit (10 percent opacity), while the GA Rule (g) fuel sulfur content limit is subsumed by the fuel requirement specified in Conditions 3.3.2 and 3.3.12. Since the turbines fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with both GA Rule (b) and (g) limits is expected.

<u>Duct Burners DB8A and DB8B</u>

The duct burners are subject to Georgia Air Quality Control Rule 391-3-1-.02(2)(d) "Fuel Burning Equipment." Since they were constructed after 1972, Georgia Rule 391-3-1-.02(2)(d)3. limits the opacity of the emissions from the duct burners to twenty (20) percent. Also, the allowable PM emission rates from the duct burners are specified by Georgia Rule 391-3-1-.02(2)(d)2.(ii), as follows:

$P = 0.5 * (10 / R)^{0.5}$

Where P equals the allowable PM emission rate in pounds per million BTU and R equals the heat input in million BTUs per hour.

The GA Rule (d) PM and visible emission limits are subsumed by the PM BACT limits in Conditions 3.3.6c. and e. Since the duct burners fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with both limits are expected.

The duct burners are also subject to the fuel sulfur content limit specified in GA Rule (g). Since the duct burners fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with GA Rule (g) 2.5-percent fuel sulfur content limit is expected.

C. Permit Conditions

Condition 3.3.1 defines the common stacks for the combustion turbines and duct burners.

Condition 3.3.2 limits the combustion turbines to fire only natural gas including Subpart KKKK citation.

Condition 3.3.3 limits the duct burners to fire only natural gas including Subpart KKKK citation.

Condition 3.3.4 defines the NOx BACT 12-month rolling period emission limit for the combined cycle block.

Condition 3.3.5 defines the CO BACT 12-month rolling period emission limit for the combined cycle block.

Condition 3.3.6 includes the NOx, CO, PM, VOC, and visible emission BACT limits for the combined cycle block.

Condition 3.3.7 defines BACT control technology to be employed for NOx on the combustion turbines.

Condition 3.3.8 defines BACT control technology to be employed for NOx on the duct burners.

Condition 3.3.9 defines BACT control technology to be employed for NOx on the combined combustion turbine and duct burner stacks.

Condition 3.3.10 defines startup and shutdown for the combined cycle block.

Condition 3.3.11 subjects the combustion turbines (ID Nos. CT8A and CT8B) to 40 CFR 63 Subpart A and Subpart YYYY. Note that both CT8A and CT8B were constructed before January 14, 2003, they are not subject to any requirement of 40 CFR 63 Subpart A and Subpart YYYY.

Condition 3.3.12 subjects the combustion turbines and duct burners (ID Nos. CT8A, CT8B, DB8A, and DB8B) to 40 CFR 60 Subpart A and Subpart KKKK.

Condition 3.3.13 includes the NSPS Subpart KKKK fuel sulfur content limit.

Condition 3.3.14 includes the NSPS Subpart KKKK NOx limits.

IV. Testing Requirements (with Associated Record Keeping and Reporting)

A. General Testing Requirements

The permit includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division. Additionally, a written notification of any performance test(s) is required 30 days (or sixty (60) days for tests required by 40 CFR Part 63) prior to the date of the test(s) and a test plan is required to be submitted with the test notification. Test methods and procedures for determining compliance with applicable emission limitations are listed and test results are required to be submitted to the Division within 60 days of completion of the testing.

The General Testing requirements are specified in Permit Condition Nos. 4.1.1 through 4.1.3.

Condition 4.1.3f now references Method 5 and/or 201A.

B. Specific Testing Requirements

According to pages 29, 30, and 31 of the 2001 preliminary determination, the following table summarizes individual equipment testing requirements:

Pollutant	**Combustion Turbine and Duct Burner Stack (40 CFR 52.21(j)2)**
NO_x	Method 7E is performed at two operating loads
SO_2	No testing required
Opacity	No testing required.
CO	Method 10 at base and 60% operating load
VOC	Method TO-14A at base and 60% operating load (performed during CO testing)
PM/PM_{10}	Method 5
HAPs (formaldehyde)	Method 0011 at base and 60% operating load

Performance testing was conducted on March 11 through March 14, 2003 for NOx to show compliance with the NOx limits in Permit Condition No. 3.3.6a. The test results passed.

Performance testing was conducted on March 11 through March 14, 2003 for CO to show compliance with the CO limits in Permit Condition No. 3.3.6b. The test results passed.

Additional performance testing was conducted on October 19, 2005 for CO to show compliance with the CO limits in Permit Condition No. 3.3.6b. The test results passed.

Performance testing was conducted on March 12, 2003 and March 13, 2003 for particulate matter to show compliance with the particulate matter limit in Permit Condition No. 3.3.6c. The test results passed.

Performance testing was conducted on January 20, 2004, January 21, 2004, and February 03, 2004 for VOC for Permit Condition No. 3.3.6d. The test results passed.

Additional performance testing was conducted on October 19, 2005 for VOC to show compliance with the VOC limits in Permit Condition No. 3.3.6d. The testing was done to retest using Method TO-14A, the method that the division deemed an acceptable method in lieu of Method 25.3 as listed in Permit No. 4911-149-0006-V-01-0. The test results passed.

Performance testing was conducted on March 11 through March 14, 2003 for formaldehyde to show compliance with Permit Condition No. 4.2.1f. as noted in Permit No. 4911-149-0006-V-01-0. The test results passed.

Since the turbines and duct burners fire exclusively on natural gas, and the initial performance testing demonstrated compliance with a good margin, VOC, PM, and opacity are expected to be below the associated BACT limits. No additional testing is required.

The combined cycle blocks are equipped with NOx and CO CEMS for a continuous compliance indication method and as long as the facility maintains the CEMS as stated in the permit, no additional testing is required.

Condition 4.2.1 state the testing requirements for PM emissions.

V. Monitoring Requirements

A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring systems required by the Division be operated continuously except during monitoring system breakdowns and repairs. Monitoring system response during quality assurance activities is required to be measured and recorded. Maintenance or repair is required to be conducted in an expeditious manner.

B. Specific Monitoring Requirements

Condition 5.2.1a. requires the installation and operation of a NOx and diluent CEMS at each combustion turbine and duct burner combined stack. The NOx CEMS is used to demonstrate compliance with the NOx BACT limit in Condition 3.3.6a.

Condition 5.2.1b. requires the installation and operation of a CO and diluent CEMS at each combustion turbine and duct burner combined stack. The CO CEMS is used to demonstrate compliance with the CO BACT limit in Condition 3.3.6b.

Note that the citation blocks of Conditions 5.2.1a. and b. both contain "40 CFR 64.2(b)(1)(vi) (exemption)." Although the cited regulation does not require the operation of a NOx and CO CEMS, it was added based on the facility's request because this is the only place that the permit can include a citation for exempting the facility from the 40 CFR 64 Cam Plan requirements. Please see the next section for detailed explanation.

Condition 5.2.2 requires the facility to monitor and record the fuel consumption being fired in the combustion turbines and in each duct burner.

Condition 5.2.3 contains the monitoring requirements for the sulfur content of the natural gas by submittal of a semiannual analysis of the gas by the supplier or by the Permittee.

Condition 5.2.4 requires that the facility use the Appendix F, Procedures (*Quality Assurance Requirements for Gas Continuous Emissions Monitoring Systems Used for Compliance Determination*) contained in the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** to assess the quality and accuracy of the data acquired by the CO CEMS. The permit condition also lists the exceptions to Appendix F.

Condition 5.2.5 includes the minimum data requirement of the CO emissions data being obtained by use of the CO CEMS, for at least 75% of the turbine operation, during the calendar month. If this minimum data requirement is not met, the emissions data can be supplemented with data obtained by conducting sampling using the methods in Permit Condition No. 4.1.3.

Condition 5.2.6 defines 1-hour averages for the NOx and CO CEMs per PTM Manual.

Condition 5.2.7 includes the requirements of 40 CFR 60 Subpart KKKK.

C. Compliance Assurance Monitoring (CAM)

An emission unit is subject to the provisions of 40 CFR 64, “Compliance Assurance Monitoring” because:

- It is located at a major source that is required to obtain a Title V Permit. [§64.2(a)]
- It is subject to an emission limitation or standard for the applicable pollutant (PM). [§64.2(a)(1)]
- The facility uses a control device to achieve compliance. [§64.2(a)(2)]
- Potential pre-controlled emissions of the applicable pollutant (particulate matter) from such emission unit are at least 100 percent of major source threshold. [§64.2(a)(3)]

The combustion turbines (ID Nos. CT8A and CT8B) and duct burners (ID Nos. DB8A and DB8B) are controlled by the selective catalytic reduction (SCR) to control NOx emissions in order to comply with the NOx BACT limit. Although the combustion turbines and duct burners are controlled by a catalytic oxidation system to reduce CO emissions, the catalytic oxidation system was not required as the CO BACT in the 2001 PSD review.

The combustion turbines and duct burners are potentially subject to 40 CFR 64. However, NOx and CO emissions from the combined cycle block, via the SCR, are monitored continuously by the NOx CEMS and CO CEMS. According to 40 CFR 64.2(b)(1)(vi), they are exempt from the 40 CFR 64 requirements because of the use of a NOx CEMS and a CO CEMS.

VI. Record Keeping and Reporting Requirements

A. General Record Keeping and Reporting Requirements

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable requirements. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a quarterly basis.

Condition 6.1.7 contains the definitions of the following exceedances and excursions:

- Conditions 6.1.7a.i. and 6.1.7a.ii. state excess emissions as defined in 40 CFR 60 Subpart KKKK.

- Subparagraph b.i. defines an exceedance as any four-hour rolling average NOx emission rate which exceeds 3.0 ppmvd, corrected to 15 percent oxygen. This is in regard to the short term NOx BACT limit placed on the combustion turbines (ID Nos. CT8A and CT8B) and duct burners (ID Nos. DB8A and DB8B). This citation includes a reference to Part 52.

- Subparagraph b.ii. defines an exceedance as any three-hour rolling average carbon monoxide emission rate, which exceeds 2.0 ppmvd at 15% oxygen. This is in regard to the short term CO BACT limit placed on the combustion turbines and duct burners.

- Subparagraph b.iii. defines an exceedance as any cold startup episode whose time exceeds that allocated in Condition 3.3.10a.i.

- Subparagraph b.iv. defines an exceedance as any warm startup episode whose time exceeds that allocated in Condition 3.3.10a.ii.

- Subparagraph b.v. defines an exceedance as any hot startup episode whose time exceeds that allocated in Condition 3.3.10a.iii.

- Subparagraph b.vi. defines an exceedance as any shutdown episode whose time exceeds that allocated in Condition 3.3.10a.iv.

- Subparagraph b.vii. defines an exceedance as any twelve month total NOx emissions (tons) from the combustion turbine and duct burner stacks specified, in Condition 3.3.1, on a combined basis, which exceeds 179.6 tons. This is in regard to the long term NOx BACT limit placed on the combustion turbines and duct burners.

- Subparagraph b.viii. defines an exceedance as any twelve month total CO emissions (tons) from the combustion turbine and duct burner stacks specified, in Condition 3.3.1, on a combined basis, which exceeds 86 tons. This is in regard to the long term CO BACT limit placed on the combustion turbines and duct burners.

- Subparagraph c.i. defines an excursion as any value of the natural gas sulfur content, as determined by Condition 5.2.3, which exceeds 0.27 grains per 100 standard cubic foot.

- Subparagraphs d.i. and d.ii. require the facility to report rolling 12-month NOx and CO emissions for each month in the report required by Permit Condition No. 6.1.4.

- Subparagraphs d.iii. through d.vii. includes several reporting requirements for the operation, data verification, and RATA of the CO CEMS.

- Subparagraph d.viii. requires that the quantity of natural gas combusted monthly in the combustion turbines and duct burners be reported in the report required by Permit Condition No. 6.1.4.

B. Specific Record Keeping and Reporting Requirements

Condition 6.2.1 requires maintenance of natural gas usage records for the combustion turbines (ID Nos. CT8A and CT8B) and duct burners (ID Nos. DB8A and DB8B).

Condition 6.2.2 requires maintenance of startup and shutdown records.

Conditions 6.2.3 through 6.2.5 includes the methodology and record keeping requirements for calculating the 12 consecutive month total NOx emissions from the combine cycle block for each month in the reporting period. The emission data must include emissions from startup, shutdown, and malfunction.

Conditions 6.2.6 through 6.2.9 includes the methodology and record keeping requirements for calculating the 12 consecutive month total CO emissions from the combine cycle block for each month in the reporting period. The emission data must include emissions from startup, shutdown, and malfunction.

Condition 6.2.10 requires that the facility notify the Division of any special testing as specified in Condition 3.3.10.

Condition Nos. 6.2.11, 6.2.12, and 6.2.13 require that the facility calculate and report their total actual emissions for the 10 years following the combustion turbine upgrade projects to show compliance with the actual to predicted-actual emissions calculations that demonstrate NSR non-applicability (recordkeeping requirements from GA Rule 391-3-1-.02(7)(b)15.(i)(III) and (V)). They are requested to report the unit's annual emissions of any regulated NSR pollutant from the facility that could increase as a result of the modifications, from each combined combustion turbine and duct burner stack specified in Condition 3.3.1 during the calendar year.

VII. Specific Requirements

A. Operational Flexibility

Other than the standard conditions (7.1.1, 7.2.1, and 7.2.2), operational flexibility provisions have not been incorporated into this Title V Permit. The applicant did not include any alternative operating scenarios in their Title V Application or request any specific operational flexibility conditions.

B. Alternative Requirements

None applicable.

C. Insignificant Activities

See Permit Application on GEOS website.
See Attachment B of the permit

D. Temporary Sources

None applicable.

E. Short-Term Activities

None applicable.

F. Compliance Schedule/Progress Reports

None applicable.

G. Emissions Trading

This facility is not involved in any emission trading programs besides being part of the Acid Rain Program. This facility is currently operating under a federally enforceable emissions cap. Nothing in this permit shall prohibit this facility from participation in an emissions trading or economic incentives program provided that the permit is amended to include permit terms that ensure that the emissions trades are quantifiable and enforceable.

H. Acid Rain Requirements

This facility is subject to requirements in Title IV of the Clean Air Act. They are subject to 40 CFR 72 (permits), 73 (sulfur dioxide), and 75 (monitoring). They are not subject to the nitrogen oxide provisions (40 CFR 76) of the Acid Rain regulations because the turbines do not have the capability to burn coal.

Attachment D of Title V Permit Amendment No. 4911-149-0006-V-05-2 contains the most current Acid Rain Permit Application from the facility that covers the period from January 1, 2022 through December 31, 2026. This application is now included in Attachment D of the proposed Title V renewal permit. Also, Section 7.9 of the proposed Title V renewal permit contains the associated Title IV conditions.

I. Stratospheric Ozone Protection Requirements

The standard permit condition pursuant to 40 CFR 82 Subpart F has been included in the proposed Title V renewal permit. These Title VI requirements apply to all air conditioning and refrigeration units containing ozone-depleting substances regardless of the size of the unit or of the source. According to Applications No. TV-634172, the facility operates equipment that is subject to Title VI of the 1990 Clean Air Act Amendments.

J. Pollution Prevention

None applicable.

K. Specific Conditions

None applicable.

L. Cross State Air Pollution Rule (CSAPR) Requirements

The Clean Air Interstate Rule (CAIR) has been replaced by the Cross State Air Pollution Rule (CSAPR) [40 CFR Part 97] per the Federal Implementation Plan (FIP) and is no longer in effect. Please find additional details about the promulgation of CSPAR at the following EPA website.

https://www3.epa.gov/crossstaterule/faqs.html

As discussed in Section III.B. of this narrative, the Division has determined that the facility is subject to the requirements of CSAPR.

Permit Condition 7.15.1 identifies the units subject to CSAPR and the applicable CSAPR Programs.

Permit Condition 7.15.2 outlines the Annual NOx, SO2 and Ozone Season NOx Emissions Requirements.

Permit Condition 7.15.3 outlines the monitoring, reporting and recordkeeping requirements associated with CSAPR.

VIII. General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

Template Condition 8.14.1 was updated in September 2011 to change the default submittal deadline for Annual Compliance Certifications to February 28.

Template Condition Section 8.27 was updated in August 2014 to include more detailed, clear requirements for emergency generator engines currently exempt from SIP permitting and considered insignificant sources in the Title V permit.

Template Condition Section 8.28 was updated in August 2014 to more clearly define the applicability of the Boiler MACT or GACT for major or minor sources of HAP.

Addendum to Narrative

The 30-day public review started on month day, year and ended on month day, year. Comments were/were not received by the Division.

//If comments were received, state the commenter, the date the comments were received in the above paragraph. All explanations of any changes should be addressed below.//