Facility Name: **McDonough-Atkinson Steam-Electric Generating Plant**
City: Smyrna
County: Cobb
AIRS #: 04-13-067-00003

Application #: TV-598456
Date Application Received: September 15, 2021
Permit No: 4911-067-0003-V-05-0

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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: McDonough-Atkinson Steam-Electric Generating Plant

2. Parent/Holding Company Name

   The Southern Company/Georgia Power Company

3. Previous and/or Other Name(s)

   Plant McDonough or Plant Atkinson
   McDonough-Atkinson Combined-Cycle Facility
   Plant McDonough-Atkinson

4. Facility Location

   5551 South Cobb Drive S.E.
   Smyrna, Georgia 30080 (Cobb County)

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

   Cobb County is designated as a non-attainment area for ozone and an attainment area for all other criteria pollutants.

B. Site Determination

McDonough-Atkinson Steam-Electric Generating Plant is currently contracting with an ash processing facility located on site to process and sell some of the coal ash produced from the electric generating process at the McDonough-Atkinson Plant. Even though the ash processing facility and the McDonough-Atkinson Plant are located on contiguous property, they are deemed to be separate sources for purposes of Title V permitting due to the fact that there is no common control between Georgia Power Company and the ash processing facility. Therefore, the Title V permit for McDonough-Atkinson Steam-Electric Generating Plant covers only those operations controlled solely by Georgia Power. The ash processing facility, which is itself a minor source under 40 CFR Part 70, will continue to operate under its minor source SIP permit. There are no other facilities which could possibly be contiguous or adjacent and under common control.

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
4911-067-0003-V-04-0	March 17, 2017	Title V Renewal
4911-067-0003-V-04-1	March 29, 2019	Revision of the startup and shutdown definitions to include special testing periods
4911-067-0003-V-04-2	June 11, 2019	Retrofit duct burners for turbines 6A and 6B on Unit 6 for better flame length control
4911-067-0003-V-04-3	June 1, 2020	Renewal of the Acid Rain Permit and modifications to specific monitoring requirement conditions
4911-067-0003-V-04-4	July 20, 2021	Update the CO CEMS permit language
4911-067-0003-V-04-5	January 23, 2023	Installation of turbine upgrade to enhance durability and improve performance for gas turbines 4A and 4B on Unit 4

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)

McDonough-Atkinson Steam-Electric Generating Plant generates electricity for sale.

3. Overall Facility Process Description

McDonough-Atkinson Steam-Electric Generating Plant burns fossil fuel to generate electricity. This facility includes three combined-cycle power blocks and four simple cycle combustion turbines which primarily burn natural gas. Each power block is nominally rated at 840 MW and consists of two combustion turbines, two heat recovery steam generators with duct-burners, and one steam turbine. The combustion turbines and duct burners are primarily fired with natural gas. Two of the combustion turbines, CT4A and CT5A, also have the capability to burn ultra-low sulfur diesel as a back-up fuel and are served by two above-ground oil storage tanks. Each combustion turbine and its paired duct burner share a common stack which is 160 feet tall. Two of the three power blocks, 4 and 5, share a common auxiliary boiler for pre-heating the combustion turbine subsystems and the steam turbines, as well as cooling the combustion system during startup. Power block 6 has its own auxiliary boiler. Each auxiliary boiler stack is 50 feet tall. The four simple cycle turbines work (two two-on-one configurations) to drive two generators with a nominal capacity of 39 MW each. Each simple cycle combustion turbine has its own exhaust which is 33 to 36 feet tall. Three mechanical-draft cooling towers will provide cooling water to the combined cycle units.

4. Overall Process Flow Diagram

The facility provided process flow diagrams with their Title V permit application.

E. Regulatory Status

1. PSD/NSR

This facility is one of the 28 named source categories and is a major source under PSD regulations. The three combined-cycle power blocks and two auxiliary boilers have gone through PSD and NAA NSR. The four simple cycle turbines predate PSD.

2. Title V Major Source Status by Pollutant

Table 2: 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}	n/a			
$PM_{2.5}$	n/a			
SO_2	yes			✓
VOC	yes	✓		
NO_x	yes	✓		
CO	yes	✓		
TRS	yes			✓
H_2S	yes			✓
Individual HAP	yes	✓		
Total HAPs	yes	✓		

3. MACT Standards

This facility is a major source for HAPs. The combined-cycle combustion turbines which were constructed after January 14, 2003 and permitted to burn oil, may be subject to MACT standard 40 CFR 63 Subpart YYYY for stationary combustion turbines depending on the fuel that they burn. When the turbines are burning natural gas exclusively, they are not subject to this Subpart. If either of the two CTs that can fire oil (Emission Unit IDs: CT4A and CT5A) do so any time during a calendar year, when all CTs at the site burn oil for an aggregate of 1000 hours or more, then that CT will be classified as an oil-fired combustion turbine for that calendar year. Subpart YYYY limits formaldehyde emissions from a lean premix oil-fired stationary combustion turbine to 91 ppb at 15% oxygen when it is firing oil. Since this facility is a major source of HAP emissions, it could be subject to a future MACT standard for electric utility steam generating units.

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

Not applicable.

C. Compliance Status

This facility did not indicate any noncompliance issues in its Application.

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
CT5M	Combustion Turbine 3AA (McDonough) Installed in 1971	391-3-1-.02(2)(b), 391-3-1-.02(g), 391-3-1-.02(nnn)	n/a	None
CT6M	Combustion Turbine 3AB (McDonough) Installed in 1971	391-3-1-.02(2)(b), 391-3-1-.02(g), 391-3-1-.02(nnn)	n/a	None
CT7M	Combustion Turbine 3BA (McDonough) Installed in 1971	391-3-1-.02(2)(b), 391-3-1-.02(g), 391-3-1-.02(nnn)	n/a	None
CT8M	Combustion Turbine 3BB (McDonough) Installed in 1971	391-3-1-.02(2)(b), 391-3-1-.02(g), 391-3-1-.02(nnn)	n/a	None
CT4A	Combustion Turbine Unit 4A, Block 4 Installed in August 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, 40 CFR 63 Subpart A, 40 CFR 63 Subpart YYYY, Acid Rain	SC4A OC4A LC4A WI4A	SCR Catalytic Oxidation Dry Low NO_x Combustor Water Injection
DB4A	HRSG, for combustion turbine CT4A, supplemental Duct Burner Unit 4A, Block 4 Installed in November 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC4A OC4A LD4A	SCR Catalytic Oxidation Dry Low NO_x Combustor
CT4B	Combustion Turbine Unit 4B, Block 4 Installed in August 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC4B OC4B LC4B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB4B	HRSG, for combustion turbine CT4B, supplemental Duct Burner Unit 4B, Block 4 Installed in November 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC4B OC4B LD4B	SCR Catalytic Oxidation Dry Low NO_x Burners

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	Description		ID No.	Description
CT5A	Combustion Turbine Unit 5A, Block 5 Installed in December 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, 40 CFR 63 Subpart A, 40 CFR 63 Subpart YYYY, Acid Rain	SC5A OC5A LC5A WI5A	SCR Catalytic Oxidation Dry Low NO_x Combustor Water Injection
DB5A	HRSG, for combustion turbine CT5A, supplemental Duct Burner Unit 5A, Block 5 Installed in March 2010	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC5A OC5A LD5A	SCR Catalytic Oxidation Dry Low NO_x Burners
CT5B	Combustion Turbine Unit 5B, Block 5 Installed in December 2009	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC5B OC5B LC5B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB5B	HRSG, for combustion turbine CT5B, supplemental Duct Burner Unit 5B, Block 5 Installed in March 2010	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC5B OC5B LD5B	SCR Catalytic Oxidation Low NO_x Burners
CT6A	Combustion Turbine Unit 6A, Block 6 Installed in December 2010	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC6A OC6A LC6A	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB6A	HRSG, for combustion turbine CT6A, supplemental Duct Burner Unit 6A, Block 6 Installed in February 2011	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC6A OC6A LD6A	SCR Catalytic Oxidation Dry Low NO_x Burners
CT6B	Combustion Turbine Unit 6B, Block 6 Installed in December 2010	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC6B OC6B LC6B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB6B	HRSG, for combustion turbine CT6B, supplemental Duct Burner Unit 6B, Block 6 Installed in February 2011	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain	SC6B OC6B LD6B	SCR Catalytic Oxidation Dry Low NO_x Burners

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	Description		ID No.	Description
AB05	Auxiliary Boiler Unit 05 Installed in February 2010	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(lll), 40 CFR 60 Subpart A, 40 CFR 60 Subpart Db, 40 CFR 63 Subpart A, 40 CFR 63 Subpart DDDDD	LA05 FR05	Low NO_x Burners Flue Gas Recirculation
AB06	Auxiliary Boiler Unit 06 Installed in February 2011	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 391-3-1-.02(lll), 40 CFR 60 Subpart A, 40 CFR 60 Subpart Db, 40 CFR 63 Subpart A, 40 CFR 63 Subpart DDDDD	LA06 FR06	Low NO_x Burners Flue Gas Recirculation
PH01	Propane Heater Unit 1	391-3-1-.02(2)(b), 391-3-1-.02(2)(d), 391-3-1-.02(g), 40 CFR 63 Subpart A, 40 CFR 63 Subpart DDDDD	n/a	None

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

B. Equipment & Rule Applicability

Emission and Operating Caps:

Condition 3.2.1 limits the fuel fired in the electric generating units to natural gas, No. 2 fuel oil, biodiesel, or biodiesel blends in the combustion turbines (emission unit IDs: CT5M, CT6M, CT7M, and CT8M).

Rules and Regulations Assessment:

Georgia Rule 391-3-1-.02(2)(b) Visible Emissions
Rule (b) limits the opacity of visible emissions to 40% or less from any air contaminant source subject to another standard under the provisions of 391-3-1-.02(2). This rule applies to the combustion turbines, duct burners, and auxiliary boilers at the facility. Other, more stringent opacity limits may apply.

Georgia Rule 391-3-1-.02(2)(d) for Fuel-burning Equipment
Rule (d) limits opacity, particulate matter (PM), and nitrogen oxides (NO_x) emissions from fuel-burning equipment. The allowable particulate matter emission rates are 0.10 lb/MMBtu for each duct burner. For each auxiliary boiler, the allowable particulate matter is based on an equation relating the heat input to the emission limit (0.11 lb/MMBtu at the design capacity of 200 MMBtu/hr). Secondly, this regulation limits visible emissions from each affected unit to no more than 20% opacity except for one 6-minute period in any hour of no more than 27% opacity. This rule also limits the allowable NO_x emission rates from each duct burner are 0.3 lb/MMBtu when firing oil, and 0.2 lb/MMBtu when firing gas.

Georgia Rule 391-3-1-.02(2)(g) Sulfur Dioxide
Rule (g) applies to the combustion turbines, duct burners, and auxiliary boilers for fuel sulfur content since the turbines, burners, and boilers are fuel-burning sources under the State Rules. Rule (g) limits the fuel sulfur content to 3.0 percent, by weight, for fuel burning sources whose heat input capacity is greater than 100 MMBtu/hr. Fuels types and sulfur content of fuels burned in this equipment will be limited to comply with this Rule.

Georgia Rule 391-3-1-.02(2)(n) Fugitive Dust
Rule (n) requires reasonable precautions to prevent fugitive dust from becoming airborne and limits the opacity to 20 percent.

Georgia Rule 391-3-1-.02(2)(yy) Emissions of Nitrogen Oxides from Major Sources
Rule (yy) requires sources with potential emissions of NO_x exceeding 25 tpy in Cobb County to apply Reasonably Available Control Technology (RACT) to reduce those NO_x emissions. However, the rule also exempts individual equipment that is subject to subsections (jjj), (lll), (mmm), or (nnn). Because the auxiliary boilers are subject to Rule (lll), and the combustion turbines are subject to Rule (nnn), these units are exempt from Rule (yy). The duct burners associated with the combined-cycle electric generating units at the facility are subject to Rule(yy) and they employ low NO_x burner and selective catalytic reduction technology, and thus are in compliance with Rule (yy).

Georgia Rule 391-3-1-.02(2)(lll) NO_x Emissions from Fuel-burning Equipment
Rule (lll) establishes ozone-season NO_x emissions limits for fuel-burning equipment with a heat input rate between 10 MMBtu/hr and 250 MMBtu/hr located in specified counties, including Cobb County. Because each auxiliary boiler has a rated heat input of 200 MMBtu/hr, this rule sets the NO_x limit for those units equal to 30 ppm at 3% oxygen during the period May 1 through September 30 of each year. This rule specifically exempts combined-cycle gas turbines and associated duct burners.

Georgia Rule 391-3-1-.02(2)(nnn) NO_x Emissions from Large Stationary Gas Turbines
Rule (nnn) establishes ozone-season NO_x emissions limits for large stationary gas turbines located in specified counties, including Cobb County. Rule (nnn) requires each combustion turbine (CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B) to emit no more than 6 ppm NO_x at 15% oxygen during the period May 1 through September 30 of each year. The remaining combustion turbines (CT5M, CT6M, CT7M, and CT8M) were permitted before April 1, 2000 and are subject to a NOx emission limit of 30 ppm at 15% oxygen during May 1 through September 30 of each year.

40 CFR 60 Subpart Db - Industrial Steam Generating Unit
This regulation applies to steam generating units that commenced construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (or 100 MMBtu/hr). By definition, the auxiliary boilers would be subject to Subpart Db. Because the two auxiliary boilers will burn only natural gas or propane-air and will be limited to no more than 175,200 MMBtu each during any twelve consecutive months (equivalent to an annual capacity factor of 10%), those units will not be subject to Subpart Db performance standards for emissions of particulate matter, SO_2, or NO_x.

Heat recovery steam generators and duct burners regulated under Subpart KKKK are exempted from the requirements of Subparts Da, Db, and Dc.

40 CFR 60 Subpart GG - Stationary Gas Turbines

NSPS GG does not apply to CT5M, CT6M, CT7M, CT8M emission units because they were constructed before October 3, 1977 and this New Source Performance Standard (NSPS) only applies to gas turbines that were constructed after such date.

Stationary combustion turbines regulated under 40 CFR 60 Subpart KKKK are exempt from the requirements of Subpart GG.

40 CFR 60 Subpart KKKK - (Combined-cycle) Stationary Combustion Turbines

Subpart KKKK regulates emissions from combined-cycle combustion turbines. The applicability of that rule is similar to that of Subpart GG, except that Subpart KKKK applies to new, modified, and reconstructed stationary gas turbines, and their associated HRSGs and DBs. Subpart KKKK applies to all such affected facilities which commenced construction, modification, or reconstruction after February 18, 2005. Because the combined-cycle units are subject to Subpart KKKK, the applicable NSPS NO_x emissions limits for those units are as follows:

Subpart KKKK NO_x Limit:	
Firing natural gas	15 ppmv at 15% oxygen (0.43 lb/MWh)
Firing distillate oil	42 ppmv at 15% oxygen (1.3 lb/MWh)
HRSG/DB operating independent of CT	54 ppmv at 15% oxygen (0.86 lb/MWh)

Subpart KKKK also establishes an SO_2 emission standard equal to 0.90 lb/MWh. Alternatively, the source may choose to comply with the Subpart KKKK limit on fuel-sulfur content equal to 0.060 lb-SO_2/MMBtu. This is approximately equivalent to a sulfur concentration in oil of 0.05% or 500 ppmw. Two of the CTs have the capacity to fire ultra low-sulfur diesel fuel (0.0015% S) as a backup fuel. This fuel will meet the Subpart KKKK limit for fuel-sulfur content and NO_x.

40 CFR 63 Subpart YYYY - Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart YYYY applies to each stationary combustion turbine as defined in 40 CFR 63.6085(a) located at a major source of HAP emissions. The combined cycle combustion turbines which were constructed after January 14, 2003 that are permitted to burn oil may be subject to the MACT standard Subpart YYYY for stationary combustion turbines depending on the fuel that they burn. When the turbines are burning natural gas exclusively, they are not subject to this Subpart. If either of the two CTs that can fire oil (CT4A and CT5A) do so any time during a calendar year and when all CTs at the site burn oil for an aggregate of 1000 hours or more, then that CT will be classified as an oil-fired combustion turbine for that calendar year. Subpart YYYY limits formaldehyde emissions from a lean premix oil-fired stationary combustion turbine to 91 ppb at 15% oxygen when it is firing oil.

A catalytic oxidation system is used as LAER for VOC emissions from each of the six CT/HRSGs. For the two combustion turbines with oil-firing capability, their catalytic oxidation systems also comply with the MACT standard for emissions of hazardous organic compounds. In particular, use of a catalytic oxidation system on each of those two units will meet the Subpart YYYY formaldehyde emission limit. To assure removal of HAPs, the 4-hour rolling average inlet temperature of the catalyst will be maintained within the range suggested by the catalyst manufacturer.

Duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart.

40 CFR 63 Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters
Subpart DDDDD applies to industrial, commercial, or institutional boilers or process heaters, located at a major source of HAPs. Industrial boilers are defined as boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. The auxiliary boilers (AB05 and AB06) are considered to be new industrial boilers since construction commenced after June 4, 2010, and therefore, will be subject to this rule.

Subpart DDDDD is not applicable to an electric utility steam generating unit, which is defined as a "fossil fuel-fired steam generating unit of more than 25 megawatts that serves a generator that produces electricity for sale." Each of the duct burners satisfies this definition, thus making them exempt from the requirements of this subpart.

C. Permit Conditions

All conditions from Permit No. 4911-067-0003-V-04-0 and subsequent amendments have been brought forward in this permit.

Condition 3.3.1 allows natural gas, and fuel oil to be combusted in combustion turbines CT4A and CT5A.

Conditions 3.3.2 and 3.3.3 allow only natural gas to be combusted in combustion turbines CT4B, CT5B, CT6A, and CT6B, and all of the respective duct burners.

Condition 3.3.4 sets the fuel sulfur limit for any oil burned in CT4A and CT5A to 0.0015 percent sulfur by weight (equivalent to 15 ppm) per 40 CFR 60 Subpart KKKK .

Condition 3.3.5 requires the installation, and operation of catalytic oxidation control equipment on the exhaust of each combustion turbine, and its paired duct burner as BACT for CO, and LAER, for VOC.

Condition 3.3.6 sets the tons per year limits for CO, VOC, and NOx for each of the combustion turbine blocks.

Condition 3.3.7 states for the purposes of this permit, the definitions of Startup, Cold Startup, Warm Startup, and Hot startup. This condition was modified to clarify the definitions of startup and shutdown and to allow for special testing.

Condition 3.3.8 establishes the combined cycle systems compliance with NSPS 40 CFR 60 Subpart A.

Condition 3.3.9 sets the short-term emission limits of NOx, CO, VOC, PM, and opacity from the combined exhaust of each new combustion turbine, and its paired duct burner while burning natural gas.

Condition 3.3.10 sets the annual oil-fired operating time limit to 1000 hours for CT4A and CT5A.

Condition 3.3.11 sets the short-term emission limits of NOx, CO, VOC, PM, and opacity from the combined exhaust of each new combustion turbine, and its paired duct burner while burning fuel oil.

Conditions 3.3.12 and 3.3.15 require compliance with NESHAP 40 CFR 63 Subpart A and 40 CFR 63 Subpart YYYY respectively. Condition 3.3.15 was modified to reflect post September 8, 2020 verbiage.

Conditions 3.3.13, and 3.3.14 together set the emission limit for formaldehyde while burning oil to 91 ppb at 15% O_2 and specify that compliance shall be demonstrated by maintaining the 4-hour rolling average catalyst inlet temperature to not exceed 1,100 °F.

Conditions 3.3.16, 3.3.17, and 3.3.18 all relate to auxiliary boilers, AB05, and AB06, and they set the allowed fuel as pipeline quality natural gas, or propane, limit the maximum heat input per rolling 12 months, and set the short-term emission limits of CO, VOC, NOx, PM, and opacity respectively.

Condition 3.3.19 sets the limit for particulate matter emission and visible opacity from the propane heater per Georgia Rule (d).

Condition 3.3.20 sets the sulfur content limit for the propane heater and Condition 3.4.2 sets the sulfur content limit for combustion turbines per Georgia Rule (g).

Condition 3.3.21 establishes the auxiliary boilers' and propane heater's compliance with Subpart DDDDD.

Condition 3.4.1 establishes visible opacity limits for combustion turbines per Georgia Rule (b).

Condition 3.4.3 contains operational conditions for combustion turbines per Georgia Rule (nnn).

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.

Condition 4.1.3.g has been modified to include Method 8 per 40 CFR 60 Subpart KKKK, condition 4.1.3.k has been modified to include Method 10B per 40 CFR 63 Subpart DDDDD, condition 4.1.3.m has been added to include Method 20 per 40 CFR Subpart KKKK, and condition 4.1.3.o has been modified to remove ASTM D3120 for the determination of sulfur content in liquid fuels.

B. Specific Testing Requirements

All conditions from Permit No. 4911-067-0003-V-04-0 and subsequent amendments have been brought forward in this permit.

Condition 4.2.1 and 4.2.2 requires a performance test for formaldehyde when the oil-fired operating time for all oil-fired turbines on site exceeds 1000 hours in any one calendar year. Condition 4.2.1 has been modified and detailed further.

Condition 4.2.3 requires the submittal of a Notification of Compliance with the emission limit for formaldehyde within 60 days after the completion of any required test.

Condition 4.2.4 requires emissions testing for VOC at five-year intervals.

Condition 4.2.5 requires demonstration of compliance with NO_X emission limit using CEMS.

Condition 4.2.6 contain the testing and compliance requirements for the combustion turbines capable of firing oil.

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

All conditions from Permit No. 4911-067-0003-V-04-0 and subsequent amendments have been brought forward in this permit.

Condition 5.2.1 requires CEMS to be installed that monitor NOx and CO emissions from the combined cycle combustion turbines. Please note CEMS or PEMS are not required to be installed on the auxiliary boilers because their capacity factor is below 10% making them not subject to Georgia Rule 391-3-1-.02(6)(a)2.(xii). This condition was modified to narrow the CEMS drift error range, making it more stringent and accurate than the current Acid Rain CEMS standards.

Condition 5.2.2 requires monitoring of the amount of fuel burned in the combustion turbines, and duct burners, oil fired operating time, and continuously measuring the inlet temperature to the oxidation catalyst.

Conditions 5.2.3, 5.2.4 and 5.2.5 require monitoring of the sulfur content of the natural gas, fuel oil, and landfill gas burned at the facility.

Condition 5.2.6 requires quality assurance procedures to be followed to ensure relative accuracy of the CO CEMS.

Condition 5.2.7 sets a minimum data requirement from the CEMS for emission level measurements from the combustion turbines, and duct burners.

Condition 5.2.8 states which emission units are subject to the CAM rule.

Conditions 5.2.9 and 5.2.10 state the performance criteria for the NOx, and CO CEMS.

Condition 5.2.11 requires the Permittee to conduct continuous malfunction monitoring and control.

Condition 5.2.12 requires good air pollution control practices should an excursion or exceedance be detected. Condition 5.2.13 requires the Division’s prompt notification should compliance failure be identified during monitoring.

Condition 5.2.14 requires boiler tune-ups and recordkeeping per Georgia Rule (lll) for boilers inside of the ozone non-attainment area in Atlanta.

Condition 5.2.15 requires recording the average NO_X concentration and O_2 percent each hour, and basing that average on a minimum of two data points.

Condition 5.2.16 states that the Permittee shall follow the Division's Procedures for Testing, and Monitoring of Air Pollutants for the installation and operation of any continuous monitoring systems at the facility.

Condition 5.2.17 states the tune-up requirements for the Auxiliary Boilers 5 and 6 and Propane Heater 1.

C. Compliance Assurance Monitoring (CAM)

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units, along with the Title V application.

Part 64 states that a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of combustion or other process design features or characteristics. The Auxiliary Boilers AB05 and AB06 and Combustion turbines CT5M, CT6M, CT7M, and CT8M are not subject to CAM because they are not equipped with control devices as defined in Part 64.1.

Therefore, the applicability only addresses the combustion turbines and duct burners, which employ catalytic oxidizers to control carbon monoxide and volatile organic compounds and selective catalytic reduction units to control nitrogen oxides. For CO and VOC, CAM is monitoring the concentration of CO and oxygen in the exhaust to the atmosphere. This approach provides a direct measurement for the CO permit limitation and an indirect assurance that the VOC emissions are within their permitted limitation, since the generation and removal of these pollutants are related. For NOx, CAM is monitoring the concentration of NOx and oxygen in the exhaust to the atmosphere. This approach provides a direct measurement for the NOx permit limitation.

The CAM Plan appears in Part 5.2 of the Permit as listed above.

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.

B. Specific Record Keeping and Reporting Requirements

All conditions from Permit No. 4911-067-0003-V-04-0 and subsequent amendments have been brought forward in this permit, with the exception of Permit Condition 6.1.9. Permit Condition 6.1.9 was removed from the permit because the annual emission statement requirement in Rule 391-3-1-.02(6)(a)4 has been removed from the Georgia Rules for Air Quality Control.

Condition 6.2.1 requires monthly fuel burning records for five years after the date and record of combustion turbines CT5M, CT6M, CT7M, or CT8M.

Condition 6.2.2 requires a statement certifying that the oil complies with the specifications of No. 2 fuel oil contained in ASTM D396, or ASTM D975.

Condition 6.2.3 requires records specifying the hours per month of operation of combustion turbines CT5M, CT6M, CT7M, or CT8M.

Condition 6.2.4 allows report submittals by electronic media.

Condition 6.2.5 requires monthly usage records to be kept of natural gas and fuel oil burned in the combustion turbines and duct burners.

Condition 6.2.7 requires records to be kept of each startup and shutdown of the combined cycle combustion turbines and has been modified at the Permittee’s request.

Condition 6.2.8 requires the calculation of a 30-day rolling average NOx emission rate for each of the combined cycle combustion turbines, and their paired duct burners.

Conditions 6.2.9, 6.2.10 and 6.2.11 require the determination, and calculation of the hourly, monthly, and 12-month rolling NOx emissions rate respectively from the combined cycle combustion turbines.

Conditions 6.2.12, 6.2.13, 6.2.14 and 6.2.15 require the determination and calculation of the three-hour average, one-hour average, monthly, and rolling 12-month CO mass emissions rates from the combined cycle combustion turbines.

Condition 6.2.16 requires the monthly heat input rate to be determined for each of the auxiliary boilers.

Conditions 6.2.17 and 6.2.18 require the calculation of the twelve consecutive month oil fired operating time, and the calendar-year oil fired operating time for each of the turbines on site that burn fuel oil.

Condition 6.2.19 requires quarterly reports to be submitted to the Division regarding operation of, and emissions from the new combined cycle combustion turbines and auxiliary boilers. This condition was updated in previous permit amendment to correct the referenced condition.

Condition 6.2.20 requires submission of the results of a RATA within 60 days of their completion.

Condition 6.2.21 requires submission of applicable notifications required in 40 CFR 63.8(f)(4).

Condition 6.2.22 requires submission of a Notification of Compliance according to 40 CFR 63.9(h)(2)(ii) for the CT4A and CT5A combustion turbines and was later modified to clarify that a performance test is not required every year if the turbines on site burn oil less than 1000 hours, and to accurately reflect the language in the rule.

Condition 6.2.23 requires records to be kept of performance tests, startups, shutdowns, and malfunctions and maintenance of control equipment. This condition has been modified to reflect changes to 40 CFR 63.6155(a) post September 8, 2020.

Condition 6.2.24 requires records to be kept in a manner that they can be readily accessed and inspected for 5 years from the date of the record.

Conditions 6.2.25 requires the Permittee to maintain records of the catalyst inlet temperature range suggested by the manufacturer of the catalytic oxidation emissions control system.

Conditions 6.2.26 and 6.2.27 require the determination of the monthly, and 12-month rolling mass emissions rate of NOx from each combined cycle combustion turbine.

Condition 6.2.28 requires the Permittee to calculate the four-hour average catalyst inlet temperature while burning oil to meet the requirements of 40 CFR 63 Subpart YYYY.

Condition 6.2.29 contains the reporting requirements for 40 CFR 63.7550(b) and (c)(1). This condition has been modified following the initial compliance report received January 29, 2021.

Condition 6.2.30 contains the records requirements for 40 CFR 63.7555(a).

Conditions 6.2.31 and 6.2.32 were added in previous permit amendment. Condition 6.2.31 requires a report of the annual special testing time be submitted with the quarterly report. Condition 6.2.32 requires that notice be given to the Division prior to any special testing on the combined cycle turbines.

New Condition 6.2.33 requires the Permittee to document and maintain a record of information relating to the Kai turbine upgrades for combustion turbines 4A and 4B.

New Condition 6.2.34 requires the Permittee to monitor NOx emissions from Block 4 (CT4A/DB4A and CT4B/DB4B) as well as calculate and maintain record of the annual emissions.

New Condition 6.2.35 requires the Permittee to submit a report containing the annual emissions of NOx from Block 4 and the unit's actual increase in emissions.

VII. Specific Requirements

A. Operational Flexibility

- Not Applicable

B. Alternative Requirements

- Not Applicable

C. Insignificant Activities

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

D. Temporary Sources

- Not Applicable

E. Short-Term Activities

- Condition 7.6.1 requires the maintenance or records for sand blasting and asbestos removal activities.

F. Compliance Schedule/Progress Reports

- The facility did not report any noncompliance issues in the application. Therefore, no compliance schedule or progress reports are necessary.

G. Emissions Trading

- Not Applicable

H. Acid Rain Requirements

- Condition 7.9.7 was modified in amendment 4911-067-0003-V-04-3 to update the Acid Rain Permit for calendar years 2020 through 2024 for Emission Units CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, CT6B/DB6B.

- Condition 7.9.8 was updated to reflect template changes to the Title V Acid Rain Permit.

I. Stratospheric Ozone Protection Requirements

The standard permit condition pursuant to 40 CFR 82 Subpart F has been included in Title V Permit No. 4911-067-0003-V-01-0. 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. Since

McDonough-Atkinson Steam-Electric Generating Plant has at least some air conditioners, chillers and refrigerators Subpart F is an applicable requirement.

McDonough-Atkinson Steam-Electric Generating Plant does not service motor vehicles, so 40 CFR 82 Subpart B is not applicable.

J. Pollution Prevention

- There are no pollution prevention provisions incorporated into this Title V Permit.

K. Specific Conditions

- None Applicable

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.