PERMIT NO. 4911-095-0109-V-02-0
ISSUANCE DATE:

GEORGIA
DEPARTMENT OF NATURAL RESOURCES

ENVIRONMENTAL PROTECTION DIVISION

Air Quality - Part 70 Operating Permit

Facility Name:	**Albany Green Energy, LLC**
Facility Address:	**508 Liberty Expressway, Southeast** **Albany, Georgia 31705, Dougherty County**
Mailing Address:	**508 Liberty Expressway, Southeast** **Albany, Georgia 31705**
Parent/Holding Company:	**Exelon Corporation**
Facility AIRS Number:	**04-13-095-00109**

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Georgia Rules for Air Quality Control, Chapter 391-3-1, adopted pursuant to and in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

The operation of a 1,037 million British thermal unit per hour (MMBtu/hr) Circulating Fluidized Bed (CFB) Biomass Cogeneration Boiler (Boiler B004) to generate power for the electrical grid and supply steam to the Procter & Gamble paper products facility, including a biomass storage pile, a sorbent storage silo, a fly ash storage silo, and a cooling tower.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the issuance date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above, for any misrepresentation made in Title V Application TV-235308 signed on April 26, 2018, any other applications upon which this Permit is based, supporting data entered therein or attached thereto, or any subsequent submittal of supporting data, or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **60** pages.

STATE OF GEORGIA
CONSTITUTION
WISDOM JUSTICE MODERATION
1776

DRAFT

Richard E. Dunn, Director
Environmental Protection Division

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PART 1.0 FACILITY DESCRIPTION

1.1 Site Determination

Albany Green Energy (AGE) is co-located with Procter & Gamble (P&G) paper products facility, with the bounds of the 1,037 million British thermal units per hour (MMBtu/hr) Circulating Fluidized Bed (CFB) Biomass Cogeneration Boiler (Boiler B004) and associated facilities owned and operated by AGE within the property/fence line of P&G. The two companies have no common ownership and operate under separate Standard Industrial Classification (SIC) codes. AGE has its own Title V permit and the two facilities (AGE and P&G) are considered the same Title V site with regards to regulatory applicability. However, each separate owner/operator will be accountable for the individual unit that it operates for compliance purposes.

1.2 Previous and/or Other Names

The Procter & Gamble Paper Products Company

1.3 Overall Facility Process Description

AGE operates a 1,037 British thermal units per hour (MMBtu/hr) CFB Biomass Cogeneration Boiler (Emission Unit ID No. B004) previously associated with the P&G's Paper Products Plant. Approximately half of the steam produced is used to generate power for the electrical grid via a steam turbine. The other half is supplied to the adjacent P&G operations.

Biomass (e.g., pre-chipped wood, bark, wood waste, peanut hulls, etc.) is the primary fuel source for the CFB Biomass Cogeneration Boiler. In addition to biomass, the CFB Biomass Cogeneration Boiler is also permitted to burn up to 350 MMBtu/hr of natural gas. The CFB Biomass Cogeneration Boiler is equipped with: a baghouse (Control Device ID No. BH-1) for control of PM emissions; a selective non-catalytic reduction (SNCR) control device (Control Device ID No. SNCR-1) for control of nitrogen oxides (NO_x) emissions; a sorbent injection scrubber (Control Device ID No. SI-1) for control of sulfur dioxide SO_2) and hydrochloric acid (HCl) emissions, as needed; and an activated carbon injection system (Control Device ID No. ACI-1) for control of mercury emissions, as needed. Emission units and additional control device associated with boiler operations include: Storage Pile (Emission Unit ID No. SP-01), Biomass Hogger (Emission Unit ID No. HOG), Biomass Silos Nos. 1 and 2 (Emission Unit ID Nos. BMS1 and BMS2) controlled by Bin Vent Fabric Filters (Control Device ID Nos. BMV1 and BMV2); Sorbent Silo (Emission Unit ID No. SS1) controlled by vent filter (Control Device ID No. VF-2); Flyash Silo (Emission Unit ID No. FAS1) controlled by vent filter (Control Device ID No. VF-1); mechanical draft, counterflow wet Cooling Tower (Emission Unit ID No. CT-1).

Ancillary to the CFB Biomass Cogeneration Boiler, AGE maintains a 1,080 horsepower (hp) diesel fuel-fired emergency engine for backup power to the boiler feedwater system (Emission Unit ID No. ES-GEN1), a 150 kilowatt (kW) diesel fuel-fired emergency generator for backup power to the steam turbine (Emission Unit ID No. ES-GEN2), and a 175 hp diesel fuel-fired firewater pump Emission Unit ID No. ES-FP1).

PART 2.0 REQUIREMENTS PERTAINING TO THE ENTIRE FACILITY

2.1 Facility Wide Emission Caps and Operating Limits

None applicable.

2.2 Facility Wide Federal Rule Standards

None applicable.

2.3 Facility Wide SIP Rule Standards

None applicable.

2.4 Facility Wide Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None applicable.

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Note: Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

3.1 Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
B004	Circulating Fluidized Bed Biomass Cogeneration Boiler – 1,037 MMBtu/hr	40 CFR 52.21 391-3-1-.02(2)(d) 391-3-1-.02(2)(g) 40 CFR 60, Subpart Da 40 CFR 63, Subpart DDDDD	3.2.1, 3.3.1 – 3.3.5, 3.3.8, 3.3.9, 3.3.12 – 3.3.21, 3.4.1, 3.4.6, 3.4.7, 3.5.1 - 3.5.3, 4.2.1 – 4.2.19, 5.2.1, 5.2.2, 5.2.5, 5.2.6 – 5.2.13, 6.1.7, 6.2.1, 6.2.2, 6.2.4, 6.2.5 – 6.2.14, 6.2.16 – 6.2.20	BH-1 SNCR-1 SI-1 ACI-1	Baghouse Selective Non-Catalytic Reduction Sorbent Injection Activated Carbon Injection
SP-01	Storage Pile	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.4.1, 3.4.2, 3.4.3, 3.4.4, 3.4.5	N/A	N/A
SS1	Sorbent Silo	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.3.6, 3.3.10, 3.4.1, 3.4.2, 3.4.3, 3.4.4, 3.4.5, 5.2.3, 5.2.4, 6.1.7	VF-2	Vent Filter
FAS1	Flyash Silo	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.3.6, 3.3.10, 3.4.1, 3.4.2, 3.4.3, 3.4.4, 3.4.5, 5.2.3, 5.2.4, 6.1.7	VF-1	Vent Filter
HOG	Biomass Hogger	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.4.1, 3.4.2, 3.4.3, 3.4.4, 3.4.5, 3.5.1	N/A	N/A
BMS1	Biomass Silo #1	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.3.6, 3.3.10, 3.4.1, 3.4.2, 3.4.3, 3.4.4, 3.4.5, 3.5.1, 5.2.3, 5.2.4, 6.1.7	BMV1	Bin Vent #1
BMS2	Biomass Silo #2	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.3.6, 3.3.10, 3.4.1, 3.4.2, 3.4.1, 3.4.3, 3.4.4, 3.4.5, 3.5.1, 5.2.3, 5.2.4, 6.1.7	BMV2	Bin Vent #2
CT-1	Cooling Tower	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(e) 391-3-1-.02(2)(n)	3.3.7, 3.3.11, 3.4.1, 3.4.2, 3.4.4, 3.4.5, 6.2.3	N/A	N/A
ES-GEN1 ES-GEN2	Emergency Engine 1 (1,080 hp, diesel) Emergency Generator 2 (150 kW, diesel)	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) 40 CFR 60, Subpart IIII 40 CFR 63, Subpart ZZZZ	3.3.22, 3.3.24 through 3.3.28, 3.4.1, 3.4.3, 6.2.16, 8.27.1, 8.27.3	N/A	N/A

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
ES-FP1	Fire Pump (175 hp, diesel)	40 CFR 52.21 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) 40 CFR 60, Subpart IIII 40 CFR 63, Subpart ZZZZ	3.3.23, 3.3.24 through 3.3.28, 3.4.1, 3.4.3, 6.2.16, 8.27.1, 8.27.3	N/A	N/A

* 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.

3.2 Equipment Emission Caps and Operating Limits

3.2.1 The Permittee shall not cause, let, suffer, permit or allow the emission of sulfur dioxide (SO_2) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 58 tons during any 12-consecutive month period.
[Avoidance of 40 CFR 52.21(j)]

3.3 Equipment Federal Rule Standards

<u>BACT Limits for the Biomass Boiler (B004)</u>

3.3.1 The Permittee shall not cause, let, suffer, permit or allow the emission of nitrogen oxides (NOx) from the Circulating Fluidized Bed Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.075 pound per million Btu (lb/MMBtu) on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
[40 CFR 52.21(j) and 391-3-1-.02(2)(d) subsumed]

3.3.2 The Permittee shall not cause, let, suffer, permit or allow the emission of particulate matter less than 10 micrometers in diameter (PM_{10}) and $PM_{2.5}$ from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.0268 pound per million Btu (lb/MMBtu), excluding periods of startup, shutdown, and malfunction.
[40 CFR 52.21(j); 391-3-1-.02(2)(d) subsumed]

3.3.3 The Permittee shall not cause, let, suffer, permit or allow the emission of carbon monoxide (CO) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.10 pound per million Btu (lb/MMBtu) on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
[40 CFR 52.21(j)]

3.3.4 The Permittee shall not cause, let, suffer, permit or allow the emission of volatile organic compounds (VOC) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.007 pound per million Btu (lb/MMBtu), excluding periods of startup, shutdown, and malfunction.
[40 CFR 52.21(j)]

3.3.5 The Permittee shall not cause, let, suffer, permit or allow the emission of Greenhouse Gases (GHG expressed as CO_2e) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 906,290 tons per consecutive 12-month period.
[40 CFR 52.21(j)]

3.3.6 The Permittee shall not cause, let, suffer, permit or allow the emission of particulate matter less than 10 micrometers in diameter (PM_{10}) and $PM_{2.5}$ from the Sorbent Storage Silo (Source Code: SS1), the Fly Ash Storage Silo (Source Code: FAS1), and Biomass Silos #1 and #2 (Source Code: BMS1 and BMS2) in amounts equal to or exceeding 0.005 grain per dry standard cubic feet (gr/dscf).
[40 CFR 52.21(j)]

3.3.7 The Permittee shall install and continuously operate and maintain a drift eliminator on the cooling tower (Source Code: CT-1) designed to limit circulating water flow drift loss to 0.0005 % percent or less.
[40 CFR 52.21(j)]

<u>BACT Compliance Method</u>

3.3.8 To comply with Condition 3.3.1, the Permittee shall operate a Selective Non-Catalytic Reduction System (Control Device ID: SNCR-1) at the stack of the Biomass Cogeneration Boiler (Source Code: B004). The Permittee shall operate Control Device SNCR-1 at all times the Biomass Cogeneration Boiler (Source Code: B004) is operating except during periods of startup, shutdown, and malfunction; the SNCR will be operated as soon as practicable but no later than 7 hours after commencement of combustion of any fuel within the boiler. Nitrogen oxides emissions must begin being included in averaging periods established under this permit upon startup of the SNCR system
[40 CFR 52.21(j)]

3.3.9 To comply with Conditions 3.3.2 and 3.3.13, the Permittee shall operate a Baghouse (Control Device ID No. BH-1) at the stack of the Biomass Cogeneration Boiler (Source Code: B004). The Permittee shall operate Control Device BH-1 at all times the Biomass Cogeneration Boiler (Source Code: B004) is operating except during periods of startup, shutdown, and malfunction; the BH-1 will be operated as soon as practicable but no later than 6 hours after commencement of combustion of any fuel in the boiler.
[40 CFR 52.21(j)]

3.3.10 To comply with Condition 3.3.6, the Permittee shall operate the following on each silo:
[40 CFR 52.21(j)]

a. Sorbent Storage Silo (Source Code: SS1) - Bin Vent Fabric Filter (Control Device ID No. VF-2),

b. Fly Ash Storage Silo (Source Code: FAS1) – Bin Vent Fabric Filter (Control Device ID No. VF-1),

c. Biomass Silo #1 (Source Code: BMS1) – Bin Vent Fabric Filter (Control Device ID No. BMV1),

d. Biomass Silo #2 (Source Code: BMS2) – Bin Vent Fabric Filter (Control Device ID No. BMV2).

The Permittee shall operate control equipment listed in a. through d. of this condition, including startup, shutdown, and malfunction.

3.3.11 To comply with Condition 3.3.7, the Permittee shall operate drift eliminators on the cooling tower (Source Code: CT-1). The Permittee shall operate the drift eliminators at all times Source CT-1 is operating, including startup, shutdown, and malfunction.
[40 CFR 52.21(j)]

<u>40 CFR 63 Subpart DDDDD Limits– For Biomass Boiler (B004)</u>

3.3.12 The Permittee shall comply with the 40 CFR 63, Subpart A "General Provisions" and 40 CFR 63, Subpart DDDDD "National Emissions Standards for Hazardous Air Pollutants for Industrial Boilers and Process Heaters" for operation of the Biomass Cogeneration Boiler (Source Code: B004).
[40 CFR 63, Subparts A and DDDDD]

3.3.13 The Permittee shall not cause, let, suffer, permit or allow the emission of filterable particulate matter (PM) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.0098 pound per million Btu (lb/MMBtu) of heat input or 0.012 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 9.b., Table 1]

3.3.14 The Permittee shall not cause, let, suffer, permit or allow the emission of carbon monoxide (CO) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 230 pounds per million by volume dry basis (ppmvd) corrected to 3% O_2 on a short-term/3 –hour average basis, 310 ppmvd at 3% O_2 on a 30-day rolling average, or 0.22 lb/MMBtu of steam output on a short-term/3-hour average basis, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 9.a.,Table 1]

3.3.15 The Permittee shall not cause, let, suffer, permit or allow the emission of hydrogen chloride (HCl) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 0.022 lb/MMBtu of heat input or 0.025 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 1.a., Table 1]

3.3.16 The Permittee shall not cause, let, suffer, permit or allow the emission of mercury (Hg) from the Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding 8.0E-07 lb/MMBtu of heat input or 8.7E-07 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 1.b., Table 1]

3.3.17 The Permittee shall not cause, let, suffer, permit or allow any visible emissions of which the opacity is equal to or greater than 20 percent opacity (6-minute average) except for one 6-minute period per hour of not more than 27 percent opacity from the Biomass Cogeneration Boiler (Source Code: B004) and its associated equipment, except periods of startup, shutdown, or malfunction.
[40 CFR 60.42Da(b) and 391-3-1-.2(2)(d)]

3.3.18 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR 60, Subpart A - "General Provisions" and 40 CFR 60, Subpart Da - "Standards of Performance for Electric Utility Steam Generating Units" for operation of the Biomass Cogeneration Boiler (Source Code: B004).
[40 CFR 60, Subparts A and Da]

3.3.19 The Permittee shall limit PM emissions from the Biomass Cogeneration Boiler (Source Code: B004) to 0.09 lb/MWh gross energy output or 0.097 lb/MWh net energy output. The Permittee shall meet the work practice standards specified in Table 3 to 40 CFR 63 Subpart DDDDD.
[40 CFR 60.42Da(e)]

3.3.20 The Permittee shall limit sulfur dioxide (SO_2) emissions from the Biomass Cogeneration Boiler (Source Code: B004) to 1.0 lb/MWh gross energy output or 1.2 lb/MWh net energy output.
[40 CFR 60.43Da(l)]

3.3.21 The Permittee shall limit nitrogen oxides (NOx) emissions from the Biomass Cogeneration Boiler (Source Code: B004) to 0.70 lb/MWh gross energy output or 0.76 lb/MWh net energy output. Alternatively, the Biomass Cogeneration Boiler (Source Code: B004) can comply with a combined NOx plus CO limit of 1.1 lb/MWh gross energy output or 1.2 lb/MWh net energy output.
[40 CFR 60.44Da(g) and 40 CFR 60.45Da(b)]

<u>40 CFR 60 Subpart IIII – Emergency Engines (ES-GEN1, ES-GEN2) and Fire Water Pump (ES-FP1)</u>

3.3.22 The Permittee shall comply with all applicable provisions of 40 CFR Part 60 New Source Performance Standards (NSPS) Subpart A - "General Provisions" and Subpart IIII – "Standards for Stationary Compression Ignition Internal Combustion Engines", for the Emergency Engines listed in Table 3.3.1. The Permittee shall comply with emission standards for non-methane hydrocarbons and nitrogen oxides (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) as listed below in Table 3.3.1 during the useful life of the engine.
[40 CFR 60, Subparts A and IIII]

Table 3.3.1

Unit ID	Emission Limit (g/kW-hr)		
Pollutant →	NMHC+NOx	CO	PM
ES-GEN1 (1,080 hp)	6.4	3.5	0.20
ES-GEN2 (150 kW)	4.0	3.5	0.20

3.3.23 The Permittee shall comply with all applicable provisions of 40 CFR Part 60 New Source Performance Standards (NSPS) Subpart A - "General Provisions" and Subpart IIII – "Standards for Stationary Compression Ignition Internal Combustion Engines", for the Fire Pump listed in Table 3.3.2. The Permittee shall comply with emission standards for non-methane hydrocarbons and nitrogen oxides (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) as listed below in Table 3.3.2 during the useful life of the engine.
[40 CFR 60, Subparts A and IIII]

Table 3.3.2

	g/kW-hr		
Pollutant →	NMHC+NOx	CO	PM
Emission Limit →	4.0	3.5	0.20

3.3.24 The Permittee shall fuel the Emergency Engines (ES-GEN1, ES-GEN2) and Fire Pump Engine (ES-FP1) listed in Table 3.3.1 and Table 3.3.2, with distillate fuel oil that has a maximum sulfur content of 15 ppm (0.0015% by weight) and either a minimum cetane index of 40 or maximum aromatic content of 35 volume percent.
[40 CFR 60.4207 and 391-3-1-.02(2)(g) subsumed]

3.3.25 The Permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR Part 63, in Subpart A – "General Provisions," and Subpart ZZZZ – "National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines" for the operation of the Emergency Engines (ES-GEN1, ES-GEN2) and Fire Pump Engine (ES-FP1) listed in Table 3.3.1 and Table 3.3.2.
[40 CFR 63 Subparts A and ZZZZ]

3.3.26 The accumulated non-emergency service (maintenance check and readiness testing) time for Emergency Engines (ES-GEN1, ES-GEN2) and Fire Pump Engine (ES-FP1) listed in Table 3.3.1 and Table 3.3.2, each shall not exceed 100 hours per year. Any operation other than emergency operation, maintenance check and readiness testing are prohibited.
[40 CFR 60.4211(f)]

3.3.27 Each of Emergency Engines (ES-GEN1, ES-GEN2) and Fire Pump Engine (ES-FP1) listed in Table 3.3.1 and Table 3.3.2 shall be operated and maintained according to the manufacturer's written specifications/instructions or procedures developed by the Permittee that are approved by the engine manufacturer, over the entire life of the engine. In addition, the Permittee shall only change those settings that are permitted by the manufacturer. The Permittee shall also meet the requirements of 40 CFR Parts 89, 94 and/or 1068 as they apply.
[40 CFR 60.4211(a)]

3.3.28 The Permittee shall install, calibrate, maintain, and operate non-resettable hour meters on the Emergency Engines (ES-GEN1, ES-GEN2) and Fire Pump Engine (ES-FP1) listed in Table 3.3.1 and Table 3.3.2, to measure and record, during all periods of operation, the cumulative total hours of operation of each engine. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 60.4209(a)]

3.4 Equipment SIP Rule Standards

3.4.1 The Permittee shall construct and operate the source or modification that is subject to Georgia Rule 391-3-1-.02(7) in accordance with the application submitted pursuant to that rule. If the Permittee constructs or operates a source or modification not in accordance with the application submitted pursuant to that rule or with the terms of any approval to construct, the Permittee shall be subject to appropriate enforcement action.
[40 CFR 52.21(r)(1)]

3.4.2 The Permittee shall not cause, let, permit, suffer, or allow the rate of emissions from each sorbent silo, flyash silo, cooling tower, and biomass silo, particulate matter in total quantities equal to or exceeding the allowable rate calculated as follows:
[391-3-1-.02(2)(e)1(i)]

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour

$E = 55\ P^{0.11} – 40$; for process input weight rate above 30 tons per hour

E = emission rate in pounds per hour
P = process input weight rate in tons per hour, excluding moisture

3.4.3 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from all process equipment, any gases which exhibit visible emissions, the opacity of which is equal to or greater than 40 percent, unless otherwise specified.
[391-3-1-.02(2)(b)1]

3.4.4 The Permittee shall take all reasonable precautions to prevent fugitive dust from becoming airborne. Reasonable precautions that should be taken to prevent dust from becoming airborne include, but are not limited to, the following:
[391-3-1-.02(2)(n)1]

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks, transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

3.4.5 The percent opacity from any fugitive dust source shall not equal or exceed twenty percent. [391-3-1-.02(2)(n)2]

3.4.6 The Permittee shall not emit sulfur dioxide from Biomass Cogeneration Boiler (Source Code: B004) in amounts equal to or exceeding:

a. 0.8 pounds of sulfur dioxide per million BTU's of heat input derived from liquid fossil fuel or derived from liquid fossil fuel and wood residue;
[391-3-1-.02(2)(g)1(i)]

b. 1.2 pounds of sulfur dioxide per million BTU's of heat input derived from solid fossil fuel or derived from solid fossil fuel and wood residue;
[391-3-1-.02(2)(g)1(ii)]

c. When different fossil fuels are burned simultaneously in any combination the applicable standard expressed as pounds of sulfur dioxide per million BTUs of heat input, shall be determined by proration using the following formula:
[391-3-1-.02(2)(g)1(iii)]

$$a = \frac{y(0.80)+z(1.2)}{y+z}$$

where:

y = percent of total heat input derived from liquid fossil fuel;

z = percent of total heat input derived from solid fossil fuel;

a = the allowable emission in pounds per million BTUs.

3.4.7 The Permittee shall not burn fuel containing more than 3 percent sulfur, by weight, in the Biomass Cogeneration Boiler (Source Code: B004), unless otherwise specified by the Director.
[391-3-1-.02(2)(g)2]

3.5 Equipment Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

3.5.1 For the purposes of this Permit, Biomass shall consist of organic matter excluding fossil fuels, including agricultural crops, plants, trees, wood, wood residues, sawmill residue, sawdust, wood chips, bark chips, and forest thinning, harvesting or clearing residues; wood residue from pallets or other wood demolition debris, peanut shells, pecan shells, cotton plants, corn stalk and plant matter including aquatic plants, grasses, stalks, vegetation, and residues including hulls, shells, or cellulose containing fibers. Paper fines generated by P&G's process operations may also be used as fuel.

Any wood wastes that have been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote are not considered biomass. Resinated wood, as defined by 40 CFR 241.2, is considered biomass material when used as a fuel in a combustion unit.
[40 CFR 52.21(j)]

3.5.2 The Permittee shall only fire biomass in the Biomass Cogeneration Boiler (Source Code: B004). Natural Gas may only be burned during startup, shutdown, and as necessary during operation and shall not exceed the firing rate of 350 MMBtu/hr.
[40 CFR 52.21(j)]

3.5.3 For the purpose of compliance with conditions associated with 40 CFR 63 Subpart DDDDD of this Permit, the following scenarios and definitions shall be used for the startup and shutdown of the Biomass Cogeneration Boiler (Source Code: B004)
[40 CFR 63.7575]

a. Startup and Shutdown definitions as defined in 40 CFR 63.7575.
[40 CFR 63.7575]

b. All continuous monitoring systems must be operated during startup and shutdown.
[Table 3, Items 5 and 6 of 40 CFR 63 Subpart DDDDD]

c. For startup of a boiler, the Permittee shall use natural gas or one of the clean fuels listed in Table 3, Item 5.b. of 40 CFR 63 Subpart DDDDD.
[Table 3, Item 5 of 40 CFR 63 Subpart DDDDD]

d. When firing biomass/bio-based solids, the Permittee shall vent emissions to the main stack(s) and engage all of the applicable control devices during startup and shutdown except limestone injection in fluidized bed combustion boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). During startup, the Permittee shall start limestone injection in fluidized bed boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible.
[Table 3, Item 5 of 40 CFR 63 Subpart DDDDD]

e. The Permittee shall comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. All monitoring data must be collected during periods of startup and shutdown, as specified in 40 CFR 63.7535(b).
[Table 3, Items 5.d. and 6 of 40 CFR 63 Subpart DDDDD]

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

4.1.1 The Permittee shall cause to be conducted a performance test at any specified emission unit when so directed by the Environmental Protection Division ("Division"). The test results shall be submitted to the Division within 60 days of the completion of the testing. Any tests shall be performed and conducted using methods and procedures that have been previously specified or approved by the Division.
[391-3-1-.02(6)(b)1(i)]

4.1.2 The Permittee shall provide the Division thirty (30) days (or sixty (60) days for tests required by 40 CFR Part 63) prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test, and shall provide with the notification a test plan in accordance with Division guidelines.
[391-3-1-.02(3)(a) and 40 CFR 63.7(b)(1)]

4.1.3 Performance and compliance tests shall be conducted, and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, 3.4 and 3.5 are as follows:

a. Method 1 or 1A, as appropriate, shall be used for selection of sampling site and number of traverse points.

b. Method 2 in addition to Method 2A, 2C, 2D, 2F or 2G, as appropriate, shall be used for stack gas flow rate.

c. Method 3, 3A or 3B, as appropriate, shall be used for gas molecular weight.

d. Method 3B shall be used to determine the emissions rate correction factor or excess air. Method 3A may be used as an alternative.

e. Method 4 shall be used for moisture determination.

f. Method 6 or 6C shall be used for the determination of SO_2 concentration.

g. Method 7 or 7E for the determination of nitrogen oxide concentration.

h. Method 9 for the determination of Opacity.

i. Method 10 for the determination of CO concentration.

j. Method 201 or Method 201A in conjunction with Method 202 shall be used to determine the PM_{10}/ $PM_{2.5}$ concentration. The minimum sampling time for each run shall be one hour. Method 5 in conjunction with Method 202 can be used as an alternative.

k. Method 25 or 25A for the determination of VOCs

l. Method 26 or Method 26A, or approved equivalent shall be used to determine hydrogen chloride (HCl) concentrations; the sampling time for each run shall be one hour.

m. Method 22 shall be used to determine visible fugitive emissions.

n. ASTM E871 or E870, or approved equivalent shall be used to determine biomass moisture content.

o. ASTM E711, or approved equivalent shall be used to determine the heat content of biomass.

p. ASTM E775, or approved equivalent shall be used to determine biomass sulfur content.

q. Method 29, 30A, or 30B, or approved equivalent as specified in Table 5 of 40 CFR Subpart DDDDD for the determination of Mercury (Hg) emissions.

r. Method 5 or 17 for the determination of particulate matter emissions.

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

4.1.4 The Permittee shall submit performance test results to the US EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI) in accordance with any applicable NSPS or NESHAP standards (40 CFR 60 or 40 CFR 63) that contain Electronic Data Reporting Requirements. This Condition is only applicable if required by an applicable standard and for the pollutant(s) subject to said standard.
[391-3-1-.02(8)(a) and 391-3-1-.02(9)(a)]

4.2 Specific Testing Requirements

4.2.1 The Permittee shall use CEMS as the compliance determination method for the Biomass Cogeneration Boiler (Source Code: B004) as follows:
[40 CFR 52.21(j), 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

a. For the initial compliance test, NOx from the steam generating unit is monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NOx emission standards under Condition 3.3.1. The 30-day average emission rate is calculated as the average of all valid hourly emissions data recorded by the monitoring system during the 30-day test period and shall exclude periods of startup and shutdown.

b. Following the date on which the initial performance test is completed or is required to be completed in Condition 4.2.1a., whichever date comes first, the Permittee shall determine compliance with the NOx emission standards in Condition 3.3.1 on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating period as the average of all of the valid hourly NOx emission data for the preceding 30 steam generating unit operating days and shall exclude periods of startup and shutdown.

c. For the initial compliance test, CO from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the CO emission standards under Condition 3.3.3. The 30-day average emission rate is calculated as the average of all valid hourly emissions data recorded by the monitoring system during the 30-day test period and shall exclude periods of startup and shutdown.

d. Following the date on which the initial performance test is completed or is required to be completed in Condition 4.2.1c., whichever date comes first, the Permittee shall determine compliance with the CO emission standards in Condition 3.3.3 on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the valid hourly CO emission data for the preceding 30 steam generating unit operating days and shall exclude periods of startup and shutdown.
[40 CFR 60.46b, 391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.2 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the restart, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 for the Biomass Cogeneration Boiler (Source Code: B004) for VOC to verify compliance with Condition 3.3.4 and furnish to the Division a written report of the results of the performance test.
[391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.3 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the initial startup, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 for the Biomass Cogeneration Boiler (Source Code: B004) for PM_{10} and $PM_{2.5}$ to verify compliance with Condition 3.3.2. Performance testing shall be conducted annually not to exceed thirteen (13) months, at a minimum. If performance tests for two consecutive years are below 75 percent of the permit limit, testing shall be conducted only once every three years, not to exceed 37 months between consecutive tests. If results obtained at such reduced test frequency are 75 percent or higher, testing shall again be required annually until two consecutive tests are less than 75 percent and reduced testing frequency shall again apply.
[40 CFR 52.21(j), 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

40 CFR 63 Subpart DDDDD

4.2.4 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the initial startup, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B004) for filterable PM to verify compliance with Condition 3.3.13. The performance testing shall be done initially as within the timeframe specified by 40 CFR 63 Subpart DDDDD. Subsequent testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.5 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the initial startup, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B004) for CO to verify compliance with Condition 3.3.14. The performance testing shall be done initially as within the timeframe specified by 40 CFR 63 Subpart DDDDD. Subsequent testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).

If a CO CEMS that meets the Performance Specifications outlined in 40 CFR 63.7525(a)(3) is used to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 of 40 CFR 63 Subpart DDDDD, CO performance tests are not required and the boiler is not subject to the oxygen concentration operating limit requirement specified in 40 CFR 63.7510(a).
[40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.6 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the initial startup, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B004) for HCl to verify compliance with Condition 3.3.15. The performance testing shall be done initially as within the timeframe specified by 40 CFR 63 Subpart DDDDD. Subsequent testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.7 Within 60 days after achieving the maximum production rate at which the sources will be operated, but no later than 180 days after the initial startup, the Permittee shall conduct performance testing using the testing methods in Condition 4.1.3 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B004) for Hg to verify compliance with Condition 3.3.16. The performance testing shall be done initially as within the timeframe specified by 40 CFR 63 Subpart DDDDD. Subsequent testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3) and 391-3-1-.03(2)(c)]

4.2.8 The Permittee shall conduct a tune-up as specified in 63.7540(a)(10) no later than 13 months after the initial startup of the Biomass Cogeneration Boiler (Source Code: B004). Annual tune-ups must be conducted no more than 13 months after the previous tune-up to demonstrate continuous compliance.
[40 CFR 63.7515(d) and 40 CFR 63.7540(a)(10)]

4.2.9 The Permittee demonstrating compliance by using particulate matter continuous parametric monitoring system (PM CPMS), shall maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of Conditions 4.2.14 through 4.2.16 and obtained during the most recent performance test run used in demonstrating compliance with the filterable PM emission limit in Conditions 3.3.13 and 3.3.19.
[40 CFR 60.49Da(t) which references 40 CFR 63.9991(a)(2), Table 4; 40 CFR 60.50Da(b)(1)]

4.2.10 For establishing operating limits with PM CPMS to demonstrate compliance with a PM emission limit, the Permittee shall operate the Biomass Cogeneration Boiler (Source Code: B004) at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run.
[40 CFR 60.49Da(t) which references 40 CFR 63.10007(a)(3)]

4.2.11 If the Permittee chooses the filterable PM method to comply with the PM emission limit in Conditions 3.3.13 and 3.3.19 and demonstrate continuous performance using a PM CPMS, the Permittee must also establish an operating limit according to Conditions 4.2.12 through 4.2.17, and Conditions 4.2.9 and 5.2.12. Should the Permittee desire to have operating limits that correspond to loads other than maximum normal operating load, the Permittee must conduct testing at those other loads to determine the additional operating limits.
[40 CFR 60.49Da(t) which references 40 CFR 10007(c)]

4.2.12 The Permittee must demonstrate initial compliance with Conditions 3.3.13 and 3.3.19 by conducting performance testing on the Biomass Cogeneration Boiler (Source Code: B004) within 60 days after achieving the maximum production rate at which the Boiler (Source Code: B004) will be operated but not later than 180 days after the restart of the boiler. The Permittee subject to Condition 4.2.9 and using a PM CPMS to demonstrate continuous performance, must also establish a site-specific operating limit in accordance with Condition 4.2.11 and Table 6 of 40 CFR 63, Subpart UUUUU. The Permittee may use only parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with Conditions 3.3.13 and 3.3.19) to establish an operating limit.

The Permittee must conduct concurrently with the PM performance test, a visible emissions performance test on the Biomass Cogeneration Boiler (Source Code: B004) to demonstrate compliance with the opacity limit in Condition 3.3.17.
[40 CFR 60.49Da(t) which references 40 CFR 63.10011(a) and (b), 391-3-1-.02(6)(b)1]

4.2.13 During the initial performance test of the Biomass Cogeneration Boiler (Source Code: B004) required by Condition 4.2.12 or any such performance test that demonstrates compliance with Conditions 3.3.13 and 3.3.19, the Permittee shall record all hourly average output values (e.g., milliamps stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for 3-hour test runs).
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(a)]

4.2.14 The Permittee shall determine the Biomass Cogeneration Boiler (Source Code: B004) operating limit as follows if the Permittee's PM performance test demonstrates that PM emissions do not exceed 75 percent of Condition 3.3.19 PM emissions limit. The Permittee will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from the PM CPMS, and the average PM result of the compliance test to establish the Permittee's operating limit. The Permittee shall calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in paragraphs a. through d. of this condition.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(i)]

a. Determine the PM CPMS instrument zero output with one of the following procedures.

i. Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

ii. Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

iii. The zero point can also be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when the boiler is not operating, but the fans are operating or the boiler is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

iv. If none of the steps in paragraphs a.i. through a.iii. of this condition are possible, the Permittee must use a zero output value provided by the manufacturer.

b. Determine the PM CPMS instrument average (x) in milliamps, and the average of your corresponding three PM compliance test runs (y), using equation 1.

$$x = \frac{1}{n}\sum_{i=1}^{n} X_i , \qquad y = \frac{1}{n}\sum_{i=1}^{n} Y_i \ldots\ldots\ldots..(Eq. 1)$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

c. With the PM CPMS instrument zero expressed in milliamps, the three run average PM CPMS milliamp value, and the three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 2.

$$R = \frac{y}{(x - z)} \ldots\ldots\ldots\ldots\ldots (Eq. 2)$$

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

y = the three run average PM lb/MWh,

x = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from paragraph a. of this condition.

d. Determine the Biomass Cogeneration Boiler (Source Code: B004) 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 2 in equation 3, below. This sets the Permittee's operating limit at the PM CPMS output value corresponding to 75 percent of the Biomass Cogeneration Boiler (Source Code: B004) emission limit.

$$O_L = z + \frac{(0.75L)}{R} \ldots\ldots\ldots (Eq. 3)$$

Where:

O_L = the operating limit for the PM CPMS on a 30-day rolling average, in milliamps,

L = the Biomass Cogeneration Boiler (Source Code: B004) PM emissions limit (Condition 3.3.23) in lb/MWh,

Z = the instrument zero in milliamps, determined from paragraph a of this condition, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 2.

4.2.15 The Permittee shall determine the Biomass Cogeneration Boiler (Source Code: B004) operating limit as follows if the Permittee's PM performance test demonstrates that PM emissions exceeds 75 percent of Condition 3.3.19 PM emissions limit. The Permittee will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the Permittee's operating limit. The Permittee shall determine the operating limit by averaging the PM CPMS milliamp output corresponding to the three PM performance test runs that demonstrate compliance with the emission limit using equation 4.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(ii)]

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \ldots\ldots\ldots (Eq. 4)$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = the Biomass Cogeneration Boiler (Source Code: B004) operating limit, in milliamps.

4.2.16 The Permittee shall meet the following requirements:
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(iii-vi)]

a. The PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

b. The PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times the Permittee's allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times the Permittee's allowable emission limit.

c. During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

d. For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

4.2.17 The Permittee must operate and maintain the Biomass Cogeneration Boiler (Source Code: B004) and control equipment such that the 30-operating day average PM CPMS output does not exceed the operating limit determined in Conditions 4.2.13 through 4.2.15 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(c), Subpart DDDDD – 40 CFR 63.7525(b) and CFR 63.7540(a)(18)]

4.2.18 The Permittee must repeat the PM performance test annually and reassess and adjust the Biomass Cogeneration Boiler (Source Code: B004) operating limit determined in Conditions 4.2.13 through 4.2.15 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance in accordance with the results of the performance test.
[40 CFR 60.49Da(t) which references 40 CFR 63.10005(d)(2)(iii), Subpart DDDDD – 40 CFR 63.7525(b) and CFR 63.7540(a)(18)]

4.2.19 The Permittee shall identify in the subsequent performance tests required in Conditions 4.2.4 through 4.2.7, whether the Biomass Cogeneration Boiler (Source Code: B004) is in compliance with the output-based emission limits or the heat input-based emission limits specified in Conditions 3.3.13 through 3.3.16.
[Subpart DDDDD – 40 CFR 63.7545(e)(2)(ii)]

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

5.1 General Monitoring Requirements

5.1.1 Any continuous monitoring system required by the Division and installed by the Permittee shall be in continuous operation and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Monitoring system response, relating only to calibration checks and zero and span adjustments, shall be measured and recorded during such periods. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.
[391-3-1-.02(6)(b)1]

5.2 Specific Monitoring Requirements

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1, 40 CFR 60.48Da, and 40 CFR 52.21]

a. A Continuous Emissions Monitoring System (CEMS) for measuring NO_x emissions discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B004). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 22 days for NO_x.

b. A Continuous Emissions Monitoring System (CEMS) for measuring SO_2 discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B004). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 22 days for SO_2 emissions.

c. A Continuous Emissions Monitoring System (CEMS) for measuring CO_2 or O_2 discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B004). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 22 days for CO_2 or O_2.

d. A Continuous Emissions Monitoring System (CEMS) for measuring CO discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B004). The minimum reportable data shall be 22 days for CO.

e. The Permittee shall, using the procedures of Appendix F, Procedure 1 (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**, assess the quality and accuracy of the data acquired by the (CEMS) required by Condition 5.2.1.a, c, d, and e.

For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

5.2.2 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1]

a. Monitor to continuously determine the sorbent injection rate for each sorbent used in the Duct Sorbent Injection System (Control Device ID: SI-1) for the Biomass Cogeneration Boiler (Source Code: B004) to demonstrate compliance according to 40 CFR 63.7525(d), 40 CFR 63.7525(i)(1), and 40 CFR 63.7525(i)(2).

b. The heat input to the Biomass Cogeneration Boiler (Source Code: B004). Data shall be recorded hourly.

c. Monitor to continuously determine the activated carbon injection rate for Hg control according to 40 CFR 63.7530(v).

d. A fuel meter to monitor fuel consumption of natural gas.

5.2.3 The Permittee shall perform a check of visible emissions from all silo vent filters and from other point sources added or replaced in accordance with this permit and Rule 391-3-1-.02(6). The Biomass Cogeneration Boiler (Source Code: B004) monitored by a PM CPMS is exempt from this condition.

The Permittee shall retain a record of the daily visible emissions (VE) log suitable for inspection and submittal, unless there is no VE for 7 consecutive days. The check shall be conducted at least once for each day or portion of each day of operation using procedures a through d below except when atmospheric condition or sun positioning prevent any opportunity to perform the daily VE check. Any operational day when atmospheric conditions or sun position prevent a daily reading shall be reported as monitor downtime in the report required by Condition 6.1.4. If there is no VE for 7 consecutive days, monitoring may be recorded on a weekly basis. If VE is observed during a weekly observation, daily VE shall be recorded until no VE is observed for 7 consecutive days.
[391-3-1-.02(6)(b)1]

a. Determine, in accordance with the procedures specified in paragraph d of this condition, if visible emissions are present at the discharge point to the atmosphere from each of the sources and record the results in the daily (VE) log. For sources that exhibit visible emissions, the Permittee shall comply with paragraph b or c of this condition.

b. For each source determined to be emitting visible emissions, the Permittee shall determine whether the emissions equal or exceed the opacity action level using the procedure specified in paragraph d of this condition, except that the person performing the determination shall have received additional training acceptable to the Division to recognize the appropriate opacity level and the determination shall cover a period of six minutes. The opacity action level is 20 percent. The results shall be recorded in the daily (VE) log. For sources that exhibit visible emissions of greater than or equal to the opacity action level, the Permittee shall comply with paragraph c of this condition.

c. For each source that requires action in accordance with paragraphs a or b of this condition, the Permittee shall determine the cause of the visible emissions and correct the problem in the most expedient manner possible.

d. The person performing the determination shall stand at a distance of at least 15 feet which is sufficient to provide a clear view of the plume against a contrasting background with the sun in the 140° sector at his/her back. Consistent with this requirement, the determination shall be made from a position such that the line of vision is approximately perpendicular to the plume direction. Only one plume shall be in the line of sight at any time when multiple stacks are in proximity to each other.

5.2.4 The Permittee shall implement a Preventive Maintenance Program for the vent filters specified in Condition 5.2.3 to assure that the provisions of Condition 3.4.2 are met. All QA/QC practices and criteria shall be stated in the Preventive Maintenance Program. The program shall be subject to review and, if necessary to assure compliance, modification by the Division and shall include the pressure drop ranges that indicate proper operation for each baghouse. At a minimum, the following operation and maintenance checks shall be made on at least a monthly basis, and a record of the findings and corrective actions taken shall be kept in a maintenance log:
[391-3-1-.02(6)(b)1]

a. Record the pressure drop across each filter and ensure that it is within the appropriate range.

b. Check dust collector hoppers and conveying systems for proper operation.

5.2.5 An oxygen analyzer system, as defined in 40 CFR 63.7575 must be installed, certified, operated, and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in 40 CFR 63.7525(a)(1) through (7). A plan for complying with this condition shall be included in the compliance plan required in Condition 6.2.9.
[40 CFR 63.7525]

5.2.6 The Permittee shall install, operate, and maintain all PM CPMS, CEMS, CMS, and all monitoring systems according to the procedures in 40 CFR 63.7525(c) through (m). A plan for complying with this condition shall be included in the compliance plan required in Condition 6.2.9.

5.2.7 The Permittee shall install, calibrate, maintain, and operate a PM Continuous Parameter Monitoring System (PM CPMS) on the Biomass Cogeneration Boiler (Source Code: B004) according to the requirements for new facilities specified in 40 CFR 63, Subpart UUUUU.
[Subpart Da - 40 CFR 60.49Da(t)]

5.2.8 For the Biomass Cogeneration Boiler (Source Code: B004) that exhausts to the atmosphere through a single dedicated stack, the Permittee shall install the required PM CPMS in the stack or at a location in the ductwork downstream of all emission control devices where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere. The Permittee shall operate the PM CPMS and record the output of the system as specified in paragraphs a. through e. below:
[40 CFR 60.49Da(t) which references 40 CFR 63.10010(a)(1), h(1-5), Subpart DDDDD – 40 CFR 63.7525(b)(1-4)]

a. Install, calibrate, operate, and maintain the PM CPMS according to the procedures in the approved site-specific monitoring plan developed in accordance with Condition 5.2.13, and meet the requirements in paragraphs a.i. through a.iii. of this condition.

   i. The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

   ii. The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

   iii. The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

b. Complete the initial PM CPMS performance evaluation no later than 180 days after the date of initial startup.

c. Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph e. of this condition. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

d. Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

e. The Permittee must collect data using the PM CPMS at all times the biomass cogeneration boiler (Source Code: B004) is operating and at the intervals specified in paragraph a.ii. of this condition, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

5.2.9 The Permittee must use all the data collected during all the Biomass Cogeneration Boiler (Source Code: B004) operating hours in assessing the compliance with the Permittee's operating limit except:
[40 CFR 60.49Da(t) which references 40 CFR 63.10010(h)(6), Subpart DDDDD – 40 CFR 63.7535]

a. Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. The Permittee must report any monitoring system malfunctions or out of control periods in the Permittee's annual deviation reports. The Permittee must report any monitoring system quality assurance or quality control activities per the requirements of 40 CFR 63.10031(b).

b. Any data collected during periods when the monitoring system is out of control as specified in the Permittee's site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. The Permittee must report any such periods in your annual deviation report;

c. Any data recorded during periods of startup or shutdown.

5.2.10 For the Biomass Cogeneration Boiler (Source Code: B004) demonstrating compliance with Conditions 3.3.13 and 3.3.19, the Permittee shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B to part 60 and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of Part 60, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20(c) and appendix A to part 75 and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR 75.21 and appendix B to part 75, may be used. Flow rate data reported to meet the requirements of 40 CFR 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75, nor shall the data have been bias adjusted according to the procedures of part 75.
[Subpart Da – 40 CFR 60.49Da(l), (m)]

5.2.11 Procedures specified in paragraphs a. through c. of this condition shall be used to determine gross energy output for the Biomass Cogeneration Boiler (Source Code: B004) demonstrating compliance with Condition 3.3.19.
[Subpart Da, 40 CFR 60.49Da(k)]

a. The Permittee of the Biomass Cogeneration Boiler (Source Code: B004) with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

b. The Permittee of the Biomass Cogeneration Boiler (Source Code: B004) with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

c. For the Biomass Cogeneration Boiler (Source Code: B004) generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of "gross energy output" specified in 40 CFR 60.41Da that is applicable to the affected facility.

5.2.12 The Permittee must, for the Biomass Cogeneration Boiler (Source Code: B004), establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal) using data from the PM CPMS and the PM performance test according to the following procedures.
[40 CFR 60.49Da(t) which references 40 CFR 63.10007 and Table 6, Subpart DDDDD – 40 CFR 63.7525]

a. Collect PM CPMS output data during the entire period of the performance tests.

b. Record the average hourly PM CPMS output for each test run in the performance test.

c. Determine the PM CPMS operating limit in accordance with the requirements of Conditions 4.2.14 through 4.2.16 from data obtained during the performance test demonstrating compliance with the filterable PM emission limitation in Conditions 3.3.13 and 3.3.19 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance.

5.2.13 If the Permittee demonstrates compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the Permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 45 days before the initial performance evaluation (where applicable) of the CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to the Biomass Cogeneration Boiler (Source Code: B004) with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of Chapter 40, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the Permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this condition and, if approved, include those in the Permittee's site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs a. through e. of this condition.
[Subpart Da – 40 CFR 60.49Da(s) which references 40 CFR 63.10000(d), and Subpart DDDDD – 40 CFR 63.7505(d)(1)]

a. The site-specific monitoring plan shall include the information specified in paragraphs d.i. through d.vii. of this condition. Alternatively, the requirements of Paragraphs d.i. through d.vii. are considered to be met for a particular CMS if:

i. The CMS is installed, certified, maintained, operated, and quality-assured either according to part 75 of Chapter 40, or appendix A or B to 40 CFR 63, Subpart UUUUU; and

ii. The recordkeeping and reporting requirements of part 75 of Chapter 40, or appendix A or B to 40 CFR 63, Subpart UUUUU, that pertain to the CMS are met.

b. If requested by the Director, Permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program).

c. The Permittee must operate and maintain the CMS according to the site-specific monitoring plan.

d. The provisions of the site-specific monitoring plan must address the following items:

i. Installation of the CMS sampling probe or other interface at a measurement location relative to the Biomass Cogeneration Boiler (Source Code: B004) such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h)

ii. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

iii. Schedule for conducting initial and periodic performance evaluations.

iv. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

v. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

vi. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

vii. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR 63, Subpart UUUUU.

PART 6.0 RECORD KEEPING AND REPORTING REQUIREMENTS

6.1 General Record Keeping and Reporting Requirements

6.1.1 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five (5) years following the date of entry. [391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)]

6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.
[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.3 The Permittee shall submit written reports of any failure to meet an applicable emission limitation or standard contained in this permit and/or any failure to comply with or complete a work practice standard or requirement contained in this permit which are not otherwise reported in accordance with Conditions 6.1.4 or 6.1.2. Such failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by this permit. The reports shall cover each semiannual period ending June 30 and December 31 of each year, shall be postmarked by August 29 and February 28, respectively following each reporting period, and shall contain the probable cause of the failure(s), duration of the failure(s), and any corrective actions or preventive measures taken.
[391-3-1-.03(10)(d)1.(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.4 The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursions as described in this permit and any monitor malfunctions for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period. In the event that there have not been any excess emissions, exceedances, excursions or malfunctions during a reporting period, the report should so state. Otherwise, the contents of each report shall be as specified by the Division's Procedures for Testing and Monitoring Sources of Air Pollutants and shall contain the following:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(iii)(A)]

a. A summary report of excess emissions, exceedances and excursions, and monitor downtime, in accordance with Section 1.5(c) and (d) of the above referenced document, including any failure to follow required work practice procedures.

b. Total process operating time during each reporting period.

c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, and any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.

d. Specific identification of each period of such excess emissions, exceedances, and excursions that occur during startups, shutdowns, or malfunctions of the affected facility. Include the nature and cause of any malfunction (if known), the corrective action taken, or preventive measures adopted.

e. The date and time identifying each period during which any required monitoring system or device was inoperative (including periods of malfunction) except for zero and span checks, and the nature of the repairs, adjustments, or replacement. When the monitoring system or device has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

6.1.5 Where applicable, the Permittee shall keep the following records:
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(ii)(A)]

a. The date, place, and time of sampling or measurement;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of such analyses; and

f. The operating conditions as existing at the time of sampling or measurement.

6.1.6 The Permittee shall maintain files of all required measurements, including continuous monitoring systems, monitoring devices, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; and adjustments and maintenance performed on these systems or devices. These files shall be kept in a permanent form suitable for inspection and shall be maintained for a period of at least five (5) years following the date of such measurements, reports, maintenance and records.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6 (a)(3)(ii)(B)]

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(iii)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

i. Any six-minute average during which the opacity from Boiler B004 is equal to or in excess of 20 percent except for one six-minute average per hour of not more than 27 percent opacity.
[40 CFR 60.49Da]

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

i. Any time any fuel other than natural gas or biomass that does not meet the definition in Condition 3.5.1 is fired in Biomass Cogeneration Boiler (Source Code: B004).

ii. Any time natural gas is fired at a rate greater than 350 MMBtu/hr in Biomass Cogeneration Boiler (Source Code: B004).

iii. Any 30-day rolling average NOx emission rate, which exceeds the limit established by Condition 3.3.1 for the Biomass Cogeneration Boiler (Source Code: B004).

iv. Any 30-day rolling CO emission rate, which exceeds the limit established by Condition 3.3.3 for the Biomass Cogeneration Boiler (Source Code: B004).

v. Any 12-month rolling total of GHG emission rate, which exceeds the limit established by Condition 3.3.5 for the Biomass Cogeneration Boiler (Source Code: B004).

vi. Any time any control equipment required in Condition 3.3.8 through 3.3.11 of the permit is not in operation or is bypassed while applicable equipment is operating. Periods of when the Biomass Cogeneration Boiler (Source Code: B004) control equipments are not in operation or are bypassed shall not be excursions if such periods are exempted per Condition 3.3.8 and 3.3.9.

vii. Any consecutive 12-month period during which emissions of SO_2 from the Biomass Cogeneration Boiler (Source Code: B004), calculated in accordance with Condition 6.2.22, equal or exceed 58 tons.
[Avoidance of 40 CFR 52.21(j)]

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. Any 30-day rolling average of sorbent injection flow rate for each sorbent used measured using the device(s) required by Condition 5.2.2 that falls below 80 percent of the injection flow rate value established in accordance with Table 7 of 40 CFR 63 Subpart DDDDD.

ii. Any 30-day rolling average of activated carbon injection flow rate measured using the device(s) required by Condition 5.2.2 that falls below 80 percent of the injection flow rate value established in accordance with Table 7 of 40 CFR 63 Subpart DDDDD.

iii. Any weekly inspection of a baghouse as required by Condition 5.2.4 revealing a problem that is not resolved in accordance with the Preventive Maintenance Program.

iv. Any 30-boiler operating day rolling average during which PM CPMS output data for the Biomass Cogeneration Boiler (Source Code: B004) exceeds the operating limit(s) for Subpart Da compliance or Subpart DDDDD compliance established during the initial performance test or subsequent performance tests.
[Subpart DDDDD – 40 CFR 63.7540(18)(iii)]

v. Any PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period which constitutes a separate violation of 40 CFR 63, Subpart DDDDD.
[Subpart DDDDD – 40 CFR 63.7540(18)(iii)]

6.2 Specific Record Keeping and Reporting Requirements

6.2.1 The Permittee shall submit a quarterly compliance report, which contains the following information:
[391-3-1-.02(6)(b)1, 40 CFR 60 Subpart Da]

a. Company name and address.

b. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

c. Date of report and beginning and ending dates of the reporting period.

d. The total fuel use by the Biomass Cogeneration Boiler (Source Code: B004), for each calendar month within the reporting period, including, but not limited to, a description of each fuel and the total fuel usage amount with units of measure.

e. A summary of the results of the performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

f. A signed statement indicating that Permittee burned only natural gas or biomass as defined in Condition 3.5.1 in the Biomass Cogeneration Boiler (Source Code: B004).

g. If there are no deviations from any emission limits that apply, a statement indicating that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

h. The 30-boiler operating day rolling average of the milliamps measurement from the PM CPMS.

The first quarterly report must cover the period beginning on the compliance date and ending on March 31, June 30, September 30, or December 31, whichever date is the first date that occurs at the end of the quarter in which initial startup is completed. The quarterly report must be post marked or delivered no later by the 60th day following the end of each reporting period. Each subsequent report must cover the reporting period from January 1 through March 31, April 1 through June 30, July 1 through September 30, or October 1 through December 31 and must be post marked or delivered no later than May 30, August 30, November 30, and February 28, respectively, whichever date is the first date following the end of the quarterly reporting period.

6.2.2 The Permittee shall determine compliance with the emissions limitations in Conditions 3.3.1 and 3.3.3 using emissions data acquired by the CEMS. The 30-day rolling average totals shall be determined as follows:
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. For the NOx emission limit required in Condition 3.3.1, the 30-day average shall be the average of all valid hours of NOx emissions data for any 30 successive operating days. The average shall exclude data from periods of startup and shutdown.

b. For CO emission limit required in Condition 3.3.3, the 30-day average shall be the average of all valid hours of CO emissions data for any 30 successive operating days. The average shall exclude data from periods of startup and shutdown.

After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

6.2.3 To demonstrate compliance with Condition 3.3.7, the Permittee shall maintain records documenting that the drift eliminator on the cooling tower CT-1 has been designed to meet the applicable limit. Such records shall be submitted for review during the first quarterly report required by Condition 6.2.1.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

6.2.4 The Permittee shall record and maintain records of the amounts of each fuel, including fuel type, combusted during each day in the Biomass Cogeneration Boiler (Source Code: B004). The Permittee shall use these records to demonstrate compliance with Conditions 3.4.6 and 3.5.2. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

6.2.5 The Permittee shall maintain the following records as they relate to the startup and shutdown of the Biomass Cogeneration Boiler (Source Code: B004):
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. The number of startups per day; the hours attributed to the startup, and the hours attributed to shutdown. If Source B004 was not in operation on any given day, the records shall so note.

b. Identify times of startup of the pollution control systems – SNCR-1, BH-1, and SI-1.

6.2.6 The Permittee shall verify that each shipment of biomass fuel received for combustion in the Biomass Cogeneration Boiler (Source Code: B004) complies with the requirements of Condition 3.5.1. Verification shall consist of fuel receipts obtained from the fuel supplier certifying that the fuel is in compliance with the definition of biomass fuel of Condition 3.5.1. The Permittee shall retain records on site for a period of at least five years in a format suitable for inspection.
[391-3-1-.02(6)(b)1]

6.2.7 The Permittee shall calculate and maintain monthly Greenhouse Gas emissions (GHG expressed as CO_2e) from the Biomass Cogeneration Boiler (Source Code: B004). The Permittee shall use the monthly calculations to calculate the consecutive 12-month rolling totals for GHG emissions for each month. The Permittee shall notify the Division in writing if the GHG emissions from the entire facility equal or exceed 906,209 tons during any consecutive twelve-month period. This notification shall be postmarked by the fifteenth day

of the following month and shall include an explanation of how the Permittee intends to attain compliance with the emission limit in Condition 3.3.5.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

6.2.8 The Permittee shall submit a written report containing the following information for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by the 60th day following the end of each reporting period, June 30, September 30, December 31, and March 31, respectively. Reporting required by this condition shall begin at the end of the quarter in which initial startup is completed.
[40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. The 30-day rolling average NOx emission rate in lbs/MMBtu from the Biomass Cogeneration Boiler (Source Code: B004), for each 30-day average period that ends during the quarterly reporting period.

b. The 30-day rolling average CO emission rate in lbs/MMBtu from the Biomass Cogeneration Boiler (Source Code: B004), for each 30-day average period that ends during the quarterly reporting period.

c. The calculated monthly and consecutive 12-month rolling totals for GHG emissions from the Biomass Cogeneration Boiler (Source Code: B001), for each month of the reporting period.

d. The type (i.e., biomass or natural gas) and amount of fuel burned in the Biomass Cogeneration Boiler (Source Code: B004) during the reporting period.

<u>40 CFR 63 Subpart DDDDD</u>

6.2.9 Within 90 days before the restart of the boiler (B004), the Permittee shall submit a compliance plan to demonstrate initial and continuous compliance with the emission limitations, fuel specification, and work practice standards for 40 CFR 63 Subpart DDDDD for the Circulating Fluidized Bed Biomass Boiler (Source Code: B004) to the Division for approval.
[40 CFR 63 Subpart DDDDD]

Initial Compliance Date

6.2.10 The Permittee shall complete the initial compliance demonstration with the emissions limits within 180 days after the restart of the source.
[40 CFR 63.7510(f)]

6.2.11 The Permittee shall demonstrate initial compliance with the applicable work practice standards in Table 3 of 40 CFR 63 Subpart DDDDD with the applicable schedule as specified in 40 CFR 63.7540(a) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the Permittee is required to complete annual tune-ups as specified in 40 CFR 63.7540(a)
[40 CFR 63.7510(g)]

Notification of Intent

6.2.12 The Permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin if you are required to conduct a performance test.
[40 CFR 63.7545(d)]

Initial Notification of Compliance Status

6.2.13 The Permittee shall submit an initial Notification of Compliance Status to the Division for Boiler B004 after restart that meets the following requirements:
[40 CFR 63.9(h)(2)(ii), 40 CFR 63.7530(e) and 40 CFR 63.7545(e)]

a. The initial Notification of Compliance Status shall be submitted before the close of business on the 60th day following the completion of the initial compliance demonstration according to 40 CFR 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs 40 CFR 63.7545(e)(1) through 40 CFR 63.7545(e)(8) as applicable.

Recordkeeping Requirements

6.2.14 The Permittee shall maintain the following records as related to Boiler B004 and 40 CFR 63 Subpart DDDDD:

a. A copy of each notification and report submitted by the Permittee to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status annual compliance reports.
[40 CFR 63.10(b)(2)(xiv) and 40 CFR 63.7555(a)(1)

b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations.

c. For each CEMS, COMS, and continuous monitoring system you must keep records according to 40 CFR 63.7555(b)(1) through 40 CFR 63.7555(b)(5)
[40 CFR 63.7555(b)]

d. Records required in Table 8 of 40 CFR 63 Subpart DDDDD including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit
[40 CFR 63.7555(c)]

e. Applicable records in 40 CFR 63.7555(d)(2) through 40 CFR 63.7555(d)(11)
[40 CFR 63.7555(d)]

f. Monthly fuel use, including the type(s) of fuel and amount(s) used
[40 CFR 63.7555(d)(1)]

g. Records of the calendar date, time, occurrence and duration of each startup and shutdown.
[40 CFR 63.7555(i)]

h. Records of the types(s) and amount(s) of fuels used during each startup and shutdown.
[40 CFR 63.7555(j)]

i. The Permittee shall maintain the records in a form suitable and readily available for expeditious review.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(a)]

j. The Permittee shall maintain each record for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(b)]

k. The Permittee must keep each record on site, or they must be accessible from on site for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee can keep the records off site for the remaining three years.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(c)]

6.2.15 The Permittee shall retain the following operating records, using the hour meters required by Permit Condition No. 3.3.28 of the permit, for the Emergency Engines (ES-GEN1, ES-GEN2) and Fire Water Pump Engines (ES-FP1) listed in Table 3.3.1 and Table 3.3.2:
[391-3-1-.02(6)(b)1]

a. Monthly operating hours for the Emergency Engines (ES-GEN1, ES-GEN2) and Fire Water Pump Engines (ES-FP1).

6.2.16 The Permittee shall maintain the following records for each Method 9 performance test conducted in accordance with Condition 4.1.3.h.
[Subpart Da, 40 CFR 60.52Da(b)(1)]

a. Dates and time intervals of all opacity observation periods;

b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

c. Copies of all visible emission observer opacity field data sheets.

6.2.17 The Permittee shall maintain the following PM CPMS records:
[Subpart DDDDD – 40 CFR 63.7555(b) and 40 CFR 60.49Da(t) which references 40 CFR 63.10032(a)(2)]

a. Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

b. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

c. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

d. Records required in Item 2, Table 7 of 40 CFR 63, Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

e. Records of the occurrence and duration of each malfunction of the Biomass Cogeneration Boiler (Source Code: B004) or the air pollution control and monitoring equipment.

f. Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

6.2.18 For any deviation of the 30-boiler operating day rolling PM CPMS average value from the established operating parameter limit, the Permittee must:
[Subpart DDDDD – 40 CFR 63.7540(a)(18)(ii)]

a. Within 48 hours of the deviation, visually inspect the Baghouse (Source Code: BH-1);

b. If inspection of the Baghouse (Source Code: BH-1) identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

c. Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. The Permittee is not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this condition.

6.2.19 The Permittee shall calculate PM emissions discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B004) by multiplying the average hourly PM output concentration (measured according to the provisions of Conditions 4.2.12 and 4.2.18), by the average hourly flow rate (measured according to Condition 5.2.10), and dividing by the average hourly gross energy output (measured according to the provisions of Condition 5.2.11) or the average hourly net energy output, as applicable.
[Subpart Da - 40 CFR 60.48Da(n)]

6.2.20 The Permittee shall calculate and maintain a record of the total monthly emissions of SO_2 from the Biomass Cogeneration Boiler (Source Code: B004). The Permittee shall use the monthly totals to calculate the Biomass Cogeneration Boiler (Source Code: B004) SO_2 emissions on a 12-month rolling basis to determine compliance with the emission limit in Condition 3.2.1. A new 12-month total shall be calculated and maintained at the end of each calendar month.
[Avoidance of 40 CFR 52.21(j)]

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.1 Operational Flexibility

7.1.1 The Permittee may make Section 502(b)(10) changes as defined in 40 CFR 70.2 without requiring a Permit revision, if the changes are not modifications under any provisions of Title I of the Federal Act and the changes do not exceed the emissions allowable under the Permit (whether expressed therein as a rate of emissions or in terms of total emissions). For each such change, the Permittee shall provide the Division and the EPA with written notification as required below in advance of the proposed changes and shall obtain any Permits required under Rules 391-3-1-.03(1) and (2). The Permittee and the Division shall attach each such notice to their copy of this Permit.
[391-3-1-.03(10)(b)5 and 40 CFR 70.4(b)(12)(i)]

a. For each such change, the Permittee's written notification and application for a construction Permit shall be submitted well in advance of any critical date (typically at least 3 months in advance of any commencement of construction, Permit issuance date, etc.) involved in the change, but no less than seven (7) days in advance of such change and shall include a brief description of the change within the Permitted facility, the date on which the change is proposed to occur, any change in emissions, and any Permit term or condition that is no longer applicable as a result of the change.

b. The Permit shield described in Condition 8.16.1 shall not apply to any change made pursuant to this condition.

7.2 Off-Permit Changes

7.2.1 The Permittee may make changes that are not addressed or prohibited by this Permit, other than those described in Condition 7.2.2 below, without a Permit revision, provided the following requirements are met:
[391-3-1-.03(10)(b)6 and 40 CFR 70.4(b)(14)]

a. Each such change shall meet all applicable requirements and shall not violate any existing Permit term or condition.

b. The Permittee must provide contemporaneous written notice to the Division and to the EPA of each such change, except for changes that qualify as insignificant under Rule 391-3-1-.03(10)(g). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the Permit shield in Condition 8.16.1.

d. The Permittee shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the Permit, and the emissions resulting from those changes.

7.2.2 The Permittee shall not make, without a Permit revision, any changes that are not addressed or prohibited by this Permit, if such changes are subject to any requirements under Title IV of the Federal Act or are modifications under any provision of Title I of the Federal Act. [Rule 391-3-1-.03(10)(b)7 and 40 CFR 70.4(b)(15)]

7.3 Alternative Requirements

[White Paper #2]

Not Applicable.

7.4 Insignificant Activities

(see Attachment B for the list of Insignificant Activities in existence at the facility at the time of permit issuance)

7.5 Temporary Sources

[391-3-1-.03(10)(d)5 and 40 CFR 70.6(e)]

Not Applicable.

7.6 Short-term Activities

(see Form D5 “Short Term Activities” of the Permit application and White Paper #1)

Not Applicable.

7.7 Compliance Schedule/Progress Reports

[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(4)]

None applicable.

7.8 Emissions Trading

[391-3-1-.03(10)(d)1(ii) and 40 CFR 70.6(a)(10)]

Not Applicable.

7.9 Acid Rain Requirements

Facility ORIS Code: 60340
Effective: January 1, 2017 through December 31, 2021

7.9.1 Emissions which exceed any allowances that the Permittee lawfully holds under Title IV of the 1990 CAAA, or the regulations promulgated thereunder, are expressly prohibited. [40 CFR 70.6(a)(4)]

7.9.2 Permit revisions are not required for increases in emissions that are authorized by SO_2 allowances acquired pursuant to the State’s Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement. [40 CFR 70.6(a)(4)(i)]

7.9.3 This Permit does not place limits on the number of SO_2 allowances the Permittee may hold. However, the Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
[40 CFR 70.6(a)(4)(ii)]

7.9.4 Any SO_2 allowances held by the Permittee shall be accounted for according to the procedures established in regulations promulgated under Title IV of the 1990 CAAA.
[40 CFR 70.6(a)(4)(iii)]

7.9.5 Each affected unit, with the exceptions specified in 40 CFR 72.9(g)(6), operated in accordance with the Acid Rain portion of this Permit shall be deemed to be operating in compliance with the Acid Rain Program.
[40 CFR 70.6(f)(3)(iii)]

7.9.6 Where an applicable requirement is more stringent than an applicable requirement of regulations promulgated under Title IV of the 1990 CAAA, both provisions shall be incorporated into the Permit and shall be enforceable.
[40 CFR 70.6(a)(1)(ii)]

7.9.7 SO_2 Allowance Allocations and NO_X Requirements for affected unit B0004:
The Permittee shall hold allowances to account for emissions.
[40 CFR 73 (SO_2) and 40 CFR 76 (NO_X)]

7.9.8 Permit Application: The Phase II Acid Rain Permit Application, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 72.50(a)(1)]

7.10 Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA)
[391-3-1-.02(10)]

7.10.1 When and if the requirements of 40 CFR Part 68 become applicable, the Permittee shall comply with all applicable requirements of 40 CFR Part 68, including the following.

a. The Permittee shall submit a Risk Management Plan (RMP) as provided in 40 CFR 68.150 through 68.185. The RMP shall include a registration that reflects all covered processes.

b. For processes eligible for Program 1, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a. and the following additional requirements:

i. Analyze the worst-case release scenario for the process(es), as provided in 40 CFR 68.25; document that the nearest public receptor is beyond the distance to a toxic or flammable endpoint defined in 40 CFR 68.22(a); and submit in the RMP the worst-case release scenario as provided in 40 CFR 68.165.

ii. Complete the five-year accident history for the process as provided in 40 CFR 68.42 and submit in the RMP as provided in 40 CFR 68.168

iii. Ensure that response actions have been coordinated with local emergency planning and response agencies
iv. Include a certification in the RMP as specified in 40 CFR 68.12(b)(4)

c. For processes subject to Program 2, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the Program 2 prevention steps provided in 40 CFR 68.48 through 68.60 or implement the Program 3 prevention steps provided in 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 2 processes as provided in 40 CFR 68.170

d. For processes subject to Program 3, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the prevention requirements of 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 3 as provided in 40 CFR 68.175

e. All reports and notification required by 40 CFR Part 68 must be submitted electronically using RMP*eSubmit (information for establishing an account can be found at www.epa.gov/rmp/rmpesubmit). Electronic Signature Agreements should be mailed to:

MAIL

Risk Management Program (RMP) Reporting Center
P.O. Box 10162
Fairfax, VA 22038

COURIER & FEDEX

Risk Management Program (RMP) Reporting Center
CGI Federal
12601 Fair Lakes Circle
Fairfax, VA 22033

Compliance with all requirements of this condition, including the registration and submission of the RMP, shall be included as part of the compliance certification submitted in accordance with Condition 8.14.1.

7.11 Stratospheric Ozone Protection Requirements (Title VI of the CAAA of 1990)

7.11.1 If the Permittee performs any of the activities described below or as otherwise defined in 40 CFR Part 82, the Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliance must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to 40 CFR 82.166.
[Note: “MVAC-like appliance” is defined in 40 CFR 82.152.]

e. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

7.11.2 If the Permittee performs a service on motor (fleet) vehicles and if this service involves an ozone-depleting substance (refrigerant) in the MVAC, the Permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include air-tight sealed refrigeration systems used for refrigerated cargo, or air conditioning systems on passenger buses using HCFC-22 refrigerant.

7.12 Revocation of Existing Permits and Amendments

The following Air Quality Permits, Amendments, and 502(b)10 are subsumed by this permit and are hereby revoked:

Air Quality Permit and Amendment Number(s)	Dates of Original Permit or Amendment Issuance
4911-095-0109-V-01-0	July 16, 2014
4911-095-0109-V-01-1	August 21, 2014
4911-095-0109-V-01-2	April 11, 2016
4911-095-0109-V-01-3	June 13, 2017
4911-095-0109-V-01-4	November 2, 2018
4911-095-0109-V-01-5	January 16, 2019

7.13 Pollution Prevention

None applicable.

7.14 Specific Conditions

None applicable.

PART 8.0 GENERAL PROVISIONS

8.1 Terms and References

8.1.1 Terms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation.

8.1.2 Where more than one condition in this Permit applies to an emission unit and/or the entire facility, each condition shall apply and the most stringent condition shall take precedence.
[391-3-1-.02(2)(a)2]

8.2 EPA Authorities

8.2.1 Except as identified as "State-only enforceable" requirements in this Permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq.
[40 CFR 70.6(b)(1)]

8.2.2 Nothing in this Permit shall alter or affect the authority of the EPA to obtain information pursuant to 42 U.S.C. 7414, "Inspections, Monitoring, and Entry."
[40 CFR 70.6(f)(3)(iv)]

8.2.3 Nothing in this Permit shall alter or affect the authority of the EPA to impose emergency orders pursuant to 42 U.S.C. 7603, "Emergency Powers."
[40 CFR 70.6(f)(3)(i)]

8.3 Duty to Comply

8.3.1 The Permittee shall comply with all conditions of this operating Permit. Any Permit noncompliance constitutes a violation of the Federal Clean Air Act and the Georgia Air Quality Act and/or State rules and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application. Any noncompliance with a Permit condition specifically designated as enforceable only by the State constitutes a violation of the Georgia Air Quality Act and/or State rules only and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(i)]

8.3.2 The Permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the Permitted activity in order to maintain compliance with the conditions of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(ii)]

8.3.3 Nothing in this Permit shall alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of Permit issuance.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(f)(3)(ii)]

8.3.4 Issuance of this Permit does not relieve the Permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Director or any other federal, state, or local agency.
[391-3-1-.03(10)(e)1(iv) and 40 CFR 70.7(a)(6)]

8.4 Fee Assessment and Payment

8.4.1 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Fees."
[391-3-1-.03(9)]

8.5 Permit Renewal and Expiration

8.5.1 This Permit shall remain in effect for five (5) years from the issuance date. The Permit shall become null and void after the expiration date unless a timely and complete renewal application has been submitted to the Division at least six (6) months, but no more than eighteen (18) months prior to the expiration date of the Permit.
[391-3-1-.03(10)(d)1(i), (e)2, and (e)3(ii) and 40 CFR 70.5(a)(1)(iii)]

8.5.2 Permits being renewed are subject to the same procedural requirements, including those for public participation and affected State and EPA review, that apply to initial Permit issuance.
[391-3-1-.03(10)(e)3(i)]

8.5.3 Notwithstanding the provisions in 8.5.1 above, if the Division has received a timely and complete application for renewal, deemed it administratively complete, and failed to reissue the Permit for reasons other than cause, authorization to operate shall continue beyond the expiration date to the point of Permit modification, reissuance, or revocation.
[391-3-1-.03(10)(e)3(iii)]

8.6 Transfer of Ownership or Operation

8.6.1 This Permit is not transferable by the Permittee. Future owners and operators shall obtain a new Permit from the Director. The new Permit may be processed as an administrative amendment if no other change in this Permit is necessary, and provided that a written agreement containing a specific date for transfer of Permit responsibility coverage and liability between the current and new Permittee has been submitted to the Division at least thirty (30) days in advance of the transfer.
[391-3-1-.03(4)]

8.7 Property Rights

8.7.1 This Permit shall not convey property rights of any sort, or any exclusive privileges.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iv)]

8.8 Submissions

8.8.1 Reports, test data, monitoring data, notifications, annual certifications, and requests for revision and renewal shall be submitted to:

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
Atlanta Tradeport, Suite 120
4244 International Parkway
Atlanta, Georgia 30354-3908

8.8.2 Any records, compliance certifications, and monitoring data required by the provisions in this Permit to be submitted to the EPA shall be sent to:

Air and EPCRA Enforcement Branch – U. S. EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-3104

8.8.3 Any application form, report, or compliance certification submitted pursuant to this Permit shall contain a certification by a responsible official of its truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
[391-3-1-.03(10)(c)2, 40 CFR 70.5(d) and 40 CFR 70.6(c)(1)]

8.8.4 Unless otherwise specified, all submissions under this permit shall be submitted to the Division only.

8.9 Duty to Provide Information

8.9.1 The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the Permit application, shall promptly submit such supplementary facts or corrected information to the Division.
[391-3-1-.03(10)(c)5]

8.9.2 The Permittee shall furnish to the Division, in writing, information that the Division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall also furnish to the Division copies of records that the Permittee is required to keep by this Permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA, if necessary, along with a claim of confidentiality.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(v)]

8.10 Modifications

8.10.1 Prior to any source commencing a modification as defined in 391-3-1-.01(pp) that may result in air pollution and not exempted by 391-3-1-.03(6), the Permittee shall submit a Permit application to the Division. The application shall be submitted sufficiently in advance of any critical date involved to allow adequate time for review, discussion, or revision of plans, if necessary. Such application shall include, but not be limited to, information describing the precise nature of the change, modifications to any emission control system, production capacity of the plant before and after the change, and the anticipated completion date of the change. The application shall be in the form of a Georgia air quality Permit application to construct or modify (otherwise known as a SIP application) and shall be submitted on forms supplied by the Division, unless otherwise notified by the Division.
[391-3-1-.03(1) through (8)]

8.11 Permit Revision, Revocation, Reopening and Termination

8.11.1 This Permit may be revised, revoked, reopened and reissued, or terminated for cause by the Director. The Permit will be reopened for cause and revised accordingly under the following circumstances:
[391-3-1-.03(10)(d)1(i)]

a. If additional applicable requirements become applicable to the source and the remaining Permit term is three (3) or more years. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if the effective date of the requirement is later than the date on which the Permit is due to expire, unless the original permit or any of its terms and conditions has been extended under Condition 8.5.3;
[391-3-1-.03(10)(e)6(i)(I)]

b. If any additional applicable requirements of the Acid Rain Program become applicable to the source;
[391-3-1-.03(10)(e)6(i)(II)] (Acid Rain sources only)

c. The Director determines that the Permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or
[391-3-1-.03(10)(e)6(i)(III) and 40 CFR 70.7(f)(1)(iii)]

d. The Director determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.
[391-3-1-.03(10)(e)6(i)(IV) and 40 CFR 70.7(f)(1)(iv)]

8.11.2 Proceedings to reopen and reissue a Permit shall follow the same procedures as applicable to initial Permit issuance and shall affect only those parts of the Permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable.
[391-3-1-.03(10)(e)6(ii)]

8.11.3 Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Director at least thirty (30) days in advance of the date the Permit is to be reopened, except that the Director may provide a shorter time period in the case of an emergency.
[391-3-1-.03(10)(e)6(iii)]

8.11.4 All Permit conditions remain in effect until such time as the Director takes final action. The filing of a request by the Permittee for any Permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, shall not stay any Permit condition.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iii)]

8.11.5 A Permit revision shall not be required for changes that are explicitly authorized by the conditions of this Permit.

8.11.6 A Permit revision shall not be required for changes that are part of an approved economic incentive, marketable Permit, emission trading, or other similar program or process for change which is specifically provided for in this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(8)]

8.12 Severability

8.12.1 Any condition or portion of this Permit which is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(5)]

8.13 Excess Emissions Due to an Emergency

8.13.1 An “emergency” means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the Permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(1)]

8.13.2 An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the Permittee demonstrates, through properly signed contemporaneous operating logs or other relevant evidence, that:
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(2) and (3)]

a. An emergency occurred and the Permittee can identify the cause(s) of the emergency;

b. The Permitted facility was at the time of the emergency being properly operated;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in the Permit; and

d. The Permittee promptly notified the Division and submitted written notice of the emergency to the Division within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

8.13.3 In an enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency shall have the burden of proof.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(4)]

8.13.4 The emergency conditions listed above are in addition to any emergency or upset provisions contained in any applicable requirement.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(5)]

8.14 Compliance Requirements

8.14.1 Compliance Certification

The Permittee shall provide written certification to the Division and to the EPA, at least annually, of compliance with the conditions of this Permit. The annual written certification shall be postmarked no later than February 28 of each year and shall be submitted to the Division and to the EPA. The certification shall include, but not be limited to, the following elements:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(5)]

a. The identification of each term or condition of the Permit that is the basis of the certification;

b. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent, based on the method or means designated in paragraph c below. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred;

c. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period;

d. Any other information that must be included to comply with section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information; and

e. Any additional requirements specified by the Division.

8.14.2 Inspection and Entry

a. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow authorized representatives of the Division to perform the following:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(2)]

i. Enter upon the Permittee's premises where a Part 70 source is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this Permit;
ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this Permit; and
iv. Sample or monitor any substances or parameters at any location during operating hours for the purpose of assuring Permit compliance or compliance with applicable requirements as authorized by the Georgia Air Quality Act.

b. No person shall obstruct, hamper, or interfere with any such authorized representative while in the process of carrying out his official duties. Refusal of entry or access may constitute grounds for Permit revocation and assessment of civil penalties.
[391-3-1-.07 and 40 CFR 70.11(a)(3)(i)]

8.14.3 Schedule of Compliance

a. For applicable requirements with which the Permittee is in compliance, the Permittee shall continue to comply with those requirements.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(A)]

b. For applicable requirements that become effective during the Permit term, the Permittee shall meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(B)]

c. Any schedule of compliance for applicable requirements with which the source is not in compliance at the time of Permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(C)]

8.14.4 Excess Emissions

a. Excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed shall be allowed provided that:
[391-3-1-.02(2)(a)7(i)]

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

b. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control.
[391-3-1-.02(2)(a)7(ii)]

c. The provisions of this condition and Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards.
[391-3-1-.02(2)(a)7(iii)]

8.15 Circumvention

State Only Enforceable Condition.

8.15.1 The Permittee shall not build, erect, install, or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of the pollutants in the gases discharged into the atmosphere.
[391-3-1-.03(2)(c)]

8.16 Permit Shield

8.16.1 Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance provided that all applicable requirements are included and specifically identified in the Permit.
[391-3-1-.03(10)(d)6]

8.16.2 Any Permit condition identified as “State only enforceable” does not have a Permit shield.

8.17 Operational Practices

8.17.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate the source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to the Division that may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source.
[391-3-1-.02(2)(a)10]

State Only Enforceable Condition.

8.17.2 No person owning, leasing, or controlling, the operation of any air contaminant sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said air contamination source or sources, of such quantities of air contaminants as will cause, or tend to cause, by themselves, or in conjunction with other air contaminants, a condition of air pollution in quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with Georgia's Rules for Air Quality Control Chapter 391-3-1 and Conditions in this Permit, shall in no way exempt a person from this provision.
[391-3-1-.02(2)(a)1]

8.18 Visible Emissions

8.18.1 Except as may be provided in other provisions of this Permit, the Permittee shall not cause, let, suffer, permit or allow emissions from any air contaminant source the opacity of which is equal to or greater than forty (40) percent.
[391-3-1-.02(2)(b)1]

8.19 Fuel-burning Equipment

8.19.1 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, in operation or under construction on or before January 1, 1972 in amounts equal to or exceeding 0.7 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.2 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, constructed after January 1, 1972 in amounts equal to or exceeding 0.5 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.3 The Permittee shall not cause, let, suffer, permit, or allow the emission from any fuel-burning equipment constructed or extensively modified after January 1, 1972, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.
[391-3-1-.02(2)(d)]

8.20 Sulfur Dioxide

8.20.1 Except as may be specified in other provisions of this Permit, the Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in any fuel burning source that has a heat input capacity below 100 million Btu's per hour.
[391-3-1-.02(2)(g)]

8.21 Particulate Emissions

8.21.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, let, permit, suffer, or allow the rate of emission from any source, particulate matter in total quantities equal to or exceeding the allowable rates shown below. Equipment in operation, or under construction contract, on or before July 2, 1968, shall be considered existing equipment. All other equipment put in operation or extensively altered after said date is to be considered new equipment.
[391-3-1-.02(2)(e)]

a. The following equations shall be used to calculate the allowable rates of emission from new equipment:

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

b. The following equation shall be used to calculate the allowable rates of emission from existing equipment:

$E = 4.1P^{0.67}$

In the above equations, E = emission rate in pounds per hour, and
P = process input weight rate in tons per hour.

8.22 Fugitive Dust
[391-3-1-.02(2)(n)]

8.22.1 Except as may be specified in other provisions of this Permit, the Permittee shall take all reasonable precautions to prevent dust from any operation, process, handling, transportation or storage facility from becoming airborne. Reasonable precautions that could be taken to prevent dust from becoming airborne include, but are not limited to, the following:

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

8.22.2 The opacity from any fugitive dust source shall not equal or exceed 20 percent.

8.23 Solvent Metal Cleaning

8.23.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, suffer, allow, or permit the operation of a cold cleaner degreaser subject to the requirements of Georgia Rule 391-3-1-.02(2)(ff) "Solvent Metal Cleaning" unless the following requirements for control of emissions of the volatile organic compounds are satisfied:
[391-3-1-.02(2)(ff)1]

a. The degreaser shall be equipped with a cover to prevent escape of VOC during periods of non-use,

b. The degreaser shall be equipped with a device to drain cleaned parts before removal from the unit,

c. If the solvent volatility is 0.60 psi or greater measured at 100 ºF, or if the solvent is heated above 120 ºF, then one of the following control devices must be used:

i. The degreaser shall be equipped with a freeboard that gives a freeboard ratio of 0.7 or greater, or

ii. The degreaser shall be equipped with a water cover (solvent must be insoluble in and heavier than water), or

iii. The degreaser shall be equipped with a system of equivalent control, including but not limited to, a refrigerated chiller or carbon adsorption system.

d. Any solvent spray utilized by the degreaser must be in the form of a solid, fluid stream (not a fine, atomized or shower type spray) and at a pressure which will not cause excessive splashing, and

e. All waste solvent from the degreaser shall be stored in covered containers and shall not be disposed of by such a method as to allow excessive evaporation into the atmosphere.

8.24 Incinerators

8.24.1 Except as specified in the section dealing with conical burners, no person shall cause, let, suffer, permit, or allow the emissions of fly ash and/or other particulate matter from any incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) "Incinerators", in amounts equal to or exceeding the following:
[391-3-1-.02(2)(c)1-4]

a. Units with charging rates of 500 pounds per hour or less of combustible waste, including water, shall not emit fly ash and/or particulate matter in quantities exceeding 1.0 pound per hour.

b. Units with charging rates in excess of 500 pounds per hour of combustible waste, including water, shall not emit fly ash and/or particulate matter in excess of 0.20 pounds per 100 pounds of charge.

8.24.2 No person shall cause, let, suffer, permit, or allow from any incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) “Incinerators”, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

8.24.3 No person shall cause or allow particles to be emitted from an incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) “Incinerators” which are individually large enough to be visible to the unaided eye.

8.24.4 No person shall operate an existing incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) “Incinerators” unless:

a. It is a multiple chamber incinerator;

b. It is equipped with an auxiliary burner in the primary chamber for the purpose of creating a pre-ignition temperature of 800^{o}F; and

c. It has a secondary burner to control smoke and/or odors and maintain a temperature of at least 1500^{o}F in the secondary chamber.

8.25 Volatile Organic Liquid Handling and Storage

8.25.1 The Permittee shall ensure that each storage tank subject to the requirements of Georgia Rule 391-3-1-.02(2)(vv) “Volatile Organic Liquid Handling and Storage” is equipped with submerged fill pipes. For the purposes of this condition and the permit, a submerged fill pipe is defined as any fill pipe with a discharge opening which is within six inches of the tank bottom.
[391-3-1-.02(2)(vv)(1)]

8.26 Use of Any Credible Evidence or Information

8.26.1 Notwithstanding any other provisions of any applicable rule or regulation or requirement of this permit, for the purpose of submission of compliance certifications or establishing whether or not a person has violated or is in violation of any emissions limitation or standard, nothing in this permit or any Emission Limitation or Standard to which it pertains, shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[391-3-1-.02(3)(a)]

8.27 Internal Combustion Engines

8.27.1 For diesel-fired internal combustion engine(s) manufactured after April 1, 2006 or modified/reconstructed after July 11, 2005, the Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart IIII – "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." Such requirements include but are not limited to:
[40 CFR 60.4200]

a. Equip all emergency generator engines with non-resettable hour meters in accordance with Subpart IIII.

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division in accordance with Subpart IIII.

c. Conduct engine maintenance prescribed by the engine manufacturer in accordance with Subpart IIII.

d. Limit non-emergency operation of each emergency generator to 100 hours per year in accordance with Subpart IIII. Non-emergency operation other than maintenance and readiness testing is prohibited for engines qualifying as "emergency generators" for the purposes of Ga Rule 391-3-1-.02(2)(mmm).

e. Maintain any records in accordance with Subpart IIII

f. Maintain a list of engines subject to 40 CFR 60 Subpart IIII, including the date of manufacture.[391-3-1-.02(6)(b)]

8.27.2 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart JJJJ - "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines," for spark ignition internal combustion engines(s) (gasoline, natural gas, liquefied petroleum gas or propane-fired) manufactured after July 1, 2007 or modified/reconstructed after June 12, 2006.
[40 CFR 60.4230]

8.27.3 The Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart ZZZZ - "National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

For diesel-fired emergency generator engines defined as "existing" in 40 CFR 63 Subpart ZZZZ (constructed prior to June 12, 2006 for area sources of HAP, constructed prior to June 12, 2006 for ≤500hp engines at major sources, and constructed prior to December 19, 2002 for >500hp engines at major sources of HAP), such requirements (if applicable) include but are not limited to:
[40 CFR 63.6580]

a. Equip all emergency generator engines with non-resettable hour meters in accordance with Subpart ZZZZ.

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division in accordance with Subpart ZZZZ.

c. Conduct the following in accordance with Subpart ZZZZ.

   i. Change oil and filter every 500 hours of operation or annually, whichever comes first

   ii. Inspect air cleaner every 1000 hours of operation or annually, whichever comes first and replace as necessary

   iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first and replace as necessary.

d. Limit non-emergency operation of each emergency generator to 100 hours per year in accordance with Subpart ZZZZ. Non-emergency operation other than maintenance and readiness testing is prohibited for engines qualifying as "emergency generators" for the purposes of Ga Rule 391-3-1-.02(2)(mmm).

e. Maintain any records in accordance with Subpart ZZZZ

f. Maintain a list of engines subject to 40 CFR 63 Subpart ZZZZ, including the date of manufacture.[391-3-1-.02(6)(b)]

8.28 Boilers and Process Heaters

8.28.1 If the facility/site is an area source of Hazardous Air Pollutants, the Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart JJJJJJ - "National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers."
[40 CFR 63.11193]

8.28.2 If the facility/site is a major source of Hazardous Air Pollutants, the Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart DDDDD - "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters."
[40 CFR 63.7480]

Attachments

A. List of Standard Abbreviations and List of Permit Specific Abbreviations
B. Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups
C. List of References
D. Acid Rain Permit Application

ATTACHMENT A

List Of Standard Abbreviations

AIRS	Aerometric Information Retrieval System	PM	Particulate Matter
APCD	Air Pollution Control Device	PM_{10} (PM10)	Particulate Matter less than 10 micrometers in diameter
ASTM	American Society for Testing and Materials	PPM (ppm)	Parts per Million
BACT	Best Available Control Technology	PSD	Prevention of Significant Deterioration
BTU	British Thermal Unit	RACT	Reasonably Available Control Technology
CAAA	Clean Air Act Amendments	RMP	Risk Management Plan
CEMS	Continuous Emission Monitoring System	SIC	Standard Industrial Classification
CERMS	Continuous Emission Rate Monitoring System	SIP	State Implementation Plan
CFR	Code of Federal Regulations	SO_2 (SO2)	Sulfur Dioxide
CMS	Continuous Monitoring System(s)	USC	United States Code
CO	Carbon Monoxide	VE	Visible Emissions
COMS	Continuous Opacity Monitoring System	VOC	Volatile Organic Compound
dscf/dscm	Dry Standard Cubic Foot / Dry Standard Cubic Meter		
EPA	United States Environmental Protection Agency		
EPCRA	Emergency Planning and Community Right to Know Act		
gr	Grain(s)		
GPM (gpm)	Gallons per minute		
H_2O (H2O)	Water		
HAP	Hazardous Air Pollutant		
HCFC	Hydro-chloro-fluorocarbon		
MACT	Maximum Achievable Control Technology		
MMBtu	Million British Thermal Units		
MMBtu/hr	Million British Thermal Units per hour		
MVAC	Motor Vehicle Air Conditioner		
MW	Megawatt		
NESHAP	National Emission Standards for Hazardous Air Pollutants		
NO_x (NOx)	Nitrogen Oxides		
NSPS	New Source Performance Standards		
OCGA	Official Code of Georgia Annotated		

List of Permit Specific Abbreviations

ATTACHMENT B

NOTE: Attachment B contains information regarding insignificant emission units/activities and groups of generic emission units/activities in existence at the facility at the time of Permit issuance. Future modifications or additions of insignificant emission units/activities and equipment that are part of generic emissions groups may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Mobile Sources	1. Cleaning and sweeping of streets and paved surfaces	
Combustion Equipment	1. Fire fighting and similar safety equipment used to train fire fighters or other emergency personnel.	
	2. Small incinerators that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act and are not considered a “designated facility” as specified in 40 CFR 60.32e of the Federal emissions guidelines for Hospital/Medical/Infectious Waste Incinerators, that are operating as follows: i) Less than 8 million BTU/hr heat input, firing types 0, 1, 2, and/or 3 waste.	
	ii) Less than 8 million BTU/hr heat input with no more than 10% pathological (type 4) waste by weight combined with types 0, 1, 2, and/or 3 waste.	
	iii) Less than 4 million BTU/hr heat input firing type 4 waste. (Refer to 391-3-1-.03(10)(g)2.(ii) for descriptions of waste types)	
	3. Open burning in compliance with Georgia Rule 391-3-1-.02 (5).	
	4. Stationary engines burning: i) Natural gas, LPG, gasoline, dual fuel, or diesel fuel which are used exclusively as emergency generators shall not exceed 500 hours per year or 200 hours per year if subject to Georgia Rule 391-3-1-.02(2)(mmm).7	
	ii) Natural gas, LPG, and/or diesel fueled generators used for emergency, peaking, and/or standby power generation, where the combined peaking and standby power generation do not exceed 200 hours per year.	
	iii) Natural gas, LPG, and/or diesel fuel used for other purposes, provided that the output of each engine does not exceed 400 horsepower and that no individual engine operates for more than 2,000 hours per year.	
	iv) Gasoline used for other purposes, provided that the output of each engine does not exceed 100 horsepower and that no individual engine operates for more than 500 hours per year.	
Trade Operations	1. Brazing, soldering, and welding equipment, and cutting torches related to manufacturing and construction activities whose emissions of hazardous air pollutants (HAPs) fall below 1,000 pounds per year.	
Maintenance, Cleaning, and Housekeeping	1. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system (or collector) serving them exclusively.	
	2. Portable blast-cleaning equipment.	
	3. Non-Perchloroethylene Dry-cleaning equipment with a capacity of 100 pounds per hour or less of clothes.	
	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	
	5. Non-routine clean out of tanks and equipment for the purposes of worker entry or in preparation for maintenance or decommissioning.	
	6. Devices used exclusively for cleaning metal parts or surfaces by burning off residual amounts of paint, varnish, or other foreign material, provided that such devices are equipped with afterburners.	
	7. Cleaning operations: Alkaline phosphate cleaners and associated cleaners and burners.	

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Laboratories and Testing	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	
	2. Research and development facilities, quality control testing facilities and/or small pilot projects, where combined daily emissions from all operations are not individually major or are support facilities not making significant contributions to the product of a collocated major manufacturing facility.	
Pollution Control	1. Sanitary waste water collection and treatment systems, except incineration equipment or equipment subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	2. On site soil or groundwater decontamination units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	3. Bioremediation operations units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	4. Landfills that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
Industrial Operations	1. Concrete block and brick plants, concrete products plants, and ready mix concrete plants producing less than 125,000 tons per year.	
	2. Any of the following processes or process equipment which are electrically heated or which fire natural gas, LPG or distillate fuel oil at a maximum total heat input rate of not more than 5 million BTU's per hour: i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.	
	ii) Porcelain enameling furnaces or porcelain enameling drying ovens.	
	iii) Kilns for firing ceramic ware.	
	iv) Crucible furnaces, pot furnaces, or induction melting and holding furnaces with a capacity of 1,000 pounds or less each, in which sweating or distilling is not conducted and in which fluxing is not conducted utilizing free chlorine, chloride or fluoride derivatives, or ammonium compounds.	
	v) Bakery ovens and confection cookers.	
	vi) Feed mill ovens.	
	vii) Surface coating drying ovens	
	3. Carving, cutting, routing, turning, drilling, machining, sawing, surface grinding, sanding, planing, buffing, shot blasting, shot peening, or polishing; ceramics, glass, leather, metals, plastics, rubber, concrete, paper stock or wood, also including roll grinding and ground wood pulping stone sharpening, provided that: i) Activity is performed indoors; & ii) No significant fugitive particulate emissions enter the environment; & iii) No visible emissions enter the outdoor atmosphere.	
	4. Photographic process equipment by which an image is reproduced upon material sensitized to radiant energy (e.g., blueprint activity, photographic developing and microfiche).	
	5. Grain, food, or mineral extrusion processes	
	6. Equipment used exclusively for sintering of glass or metals, but not including equipment used for sintering metal-bearing ores, metal scale, clay, fly ash, or metal compounds.	
	7. Equipment for the mining and screening of uncrushed native sand and gravel.	
	8. Ozonization process or process equipment.	
	9. Electrostatic powder coating booths with an appropriately designed and operated particulate control system.	
	10. Activities involving the application of hot melt adhesives where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	
	11. Equipment used exclusively for the mixing and blending water-based adhesives and coatings at ambient temperatures.	
	12. Equipment used for compression, molding and injection of plastics where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	
	13. Ultraviolet curing processes where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
American Pulverizer WS-40 Wood Hog Unit	1
Biomass Storage Pile	1
Contractor Paved Parking Lot	1
Employee Paved Parking Lots and Roads	1

ATTACHMENT B (continued)

GENERIC EMISSION GROUPS

Emission units/activities appearing in the following table are subject only to one or more of Georgia Rules 391-3-1-.02 (2) (b), (e) &/or (n). Potential emissions of particulate matter, from these sources based on TSP, are less than 25 tons per year per process line or unit in each group. Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Emissions Units / Activities	Number of Units (if appropriate)	Applicable Rules		
		Opacity Rule (b)	PM from Mfg Process Rule (e)	Fugitive Dust Rule (n)

The following table includes groups of fuel burning equipment subject only to Georgia Rules 391-3-1-.02 (2) (b) & (d).Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Fuel Burning Equipment	Number of Units
Fuel burning equipment with a rated heat input capacity of less than 10 million BTU/hr burning only natural gas and/or LPG.	
Fuel burning equipment with a rated heat input capacity of less than 5 million BTU/hr, burning only distillate fuel oil, natural gas and/or LPG.	
Any fuel burning equipment with a rated heat input capacity of 1 million BTU/hr or less.	

ATTACHMENT C

LIST OF REFERENCES

1. The Georgia Rules for Air Quality Control Chapter 391-3-1. All Rules cited herein which begin with 391-3-1 are State Air Quality Rules.

2. Title 40 of the Code of Federal Regulations; specifically 40 CFR Parts 50, 51, 52, 60, 61, 63, 64, 68, 70, 72, 73, 75, 76 and 82. All rules cited with these parts are Federal Air Quality Rules.

3. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Testing and Monitoring Sources of Air Pollutants.***

4. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Calculating Air Permit Fees***.

5. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. This information may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/ap42/index.html*.

6. The latest properly functioning version of EPA's **TANKS** emission estimation software. The software may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/software/tanks/index.html*.

7. The Clean Air Act (42 U.S.C. 7401 et seq).

8. White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995 (White Paper #1).

9. White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996 (White Paper #2).

ATTACHMENT D

ACID RAIN PERMIT APPLICATION

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ■ New ☐ Revised ☐ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name Albany Green Energy, LLC	State Georgia	Plant Code 60340

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
B0004	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 7-2014)

Facility (Source) Name (from STEP 1)	Albany Green Energy, LLC

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

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Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission

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of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with

Albany Green Energy, LLC
Facility (Source) Name (from STEP 1)

any other provision of the Act, including the provisions of title I of the Act relating

STEP 3, Cont'd.

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Craig Fierstein	
Signature	Date 12/20/2016

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