Gainesville Renewable Energy Center (GREC), LLC
GREC

Facility ID No. 0010131
Alachua County

Initial Title V Air Operation Permit

Permit No. 0010131-004-AV
(Initial Title V Air Operation Permit No. 0010131-004-AV)

Permitting Authority:

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Division of Air Resource Management
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Permit No. 0010131-004-AV
GREC
Facility ID No. 0010131
Initial Title V Air Operation Permit

This is the initial Title V air operation permit for the above referenced facility. The new plant is located within the city of Gainesville and approximately 7 miles southeast of the city of Alachua in Alachua County, Florida. Specifically the GREC facility is located on approximately 131 acres at the Gainesville Regional Utility (GRU) Deerhaven Generating Station (DGS). The UTM coordinates are Zone 17; 365.0 kilometers (km) East and 3,293.8 km North.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Effective Date: January 1, 2015
Renewal Application Due Date: May 20, 2019
Expiration Date: December 31, 2019

for: Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

JFK/dlr

SECTION I. FACILITY INFORMATION.

Subsection A. Facility Description.

The GREC is a recently constructed 100 megawatt (MW, nominal net) electric power plant utilizing a bubbling fluidized bed (BFB) boiler, fueled by clean woody biomass. The plant is located on a 131-acre site within the boundary of the Gainesville Regional Utilities (GRU) Deerhaven Generating Station (DGS) in Alachua County, Florida. The BFB boiler has a maximum heat input capacity of 1,358 million British thermal units per hour (MMBtu/hr). Other emission units at the facility include: biomass fuel delivery, preparation, storage and handling; ash handling, storage and shipment equipment; a mechanical draft cooling tower; a 1,220-horsepower (hp) emergency generator engine; a 315-hp emergency fire pump engine; and an alkaline sorbent storage silo. The facility is an electrical services plant categorized under Standard Industrial Classification No. 4911.

Subsection B. Summary of Emissions Units.

EU ID No.	Emission Unit Description
Regulated Emissions Units	
001	Biomass fuel delivery, preparation, storage and handling
002	Woody biomass-fueled BFB boiler with a maximum heat input capacity of 1,358 million British thermal units per hour (MMBtu/hr)
003	Ash handling, storage and shipment
005	1,220-horsepower (hp) emergency generator engine
006	315-hp emergency fire pump engine
007	Alkaline sorbent storage silo
Unregulated Emissions Unit	
004	Mechanical draft cooling tower

Also included in this permit are miscellaneous insignificant emissions units and/or activities (see Appendix I, List of Insignificant Emissions Units and/or Activities).

Subsection C. Applicable Regulations.

Based on the initial Title V air operation permit application received February 11, 2014, this facility is regulated as a major source of hazardous air pollutants (HAP), because it is located at a major source of HAP (i.e., GRU DGS). The existing facility is a prevention of significant deterioration (PSD) major source of air pollutants in accordance with Rule 62-212.400, F.A.C. A summary of applicable regulations is shown in the following table.

Regulation	EU No(s).
Federal Rule Citations	
40 CFR 60, New Source Performance Standards (NSPS) Subpart A, General Provisions	002, 005, 006
40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units	002
40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	005, 006
40 CFR 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart A, General Provisions	002, 005, 006
40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters	002

Regulation	EU No(s).
40 CFR 63, Subpart ZZZZ, National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	005, 006
40 CFR 75 Acid Rain Monitoring Provisions	002
40 CFR 96 Clean Air Interstate Rule	002
State Rule Citations	
Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297 Florida Administrative Code (F.A.C.)	001,002, 003, 005, 006, 007

The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section VI, Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. **Not federally Enforceable.** Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

{Permitting Note: Nothing is deemed necessary and ordered at this time.}

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

FW5. Unconfined Particulate Matter. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility are included in Appendix BMP which is contained in Section VI of the permit.

[Rule 62-296.320(4)(c), F.A.C.]

Annual Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements for additional details.

FW6. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Annual Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air**

Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

{Permitting Note: Resources to help you complete your AOR are available on the electronic AOR (EAOR) website at: http://www.dep.state.fl.us/air/emission/eaor. If you have questions or need assistance after reviewing the information posted on the EAOR website, please contact the Department by phone at (850) 717-9000 or email at eaor@dep.state.fl.us.}

{Permitting Note: The Title V Annual Emissions Fee form (DEP Form No. 62-213.900(1)) has been repealed. ***A separate Annual Emissions Fee form is no longer required to be submitted by March 1st each year.****}*

FW7. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

FW8. Prevention of Accidental Releases (Section 112(r) of CAA). If, and when, the facility becomes subject to 112(r), the permittee shall:

a. Submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent electronically through EPA's Central Data Exchange system at the following address: https://cdx.epa.gov. Information on electronically submitting risk management plans using the Central Data Exchange system is available at: http://www.epa.gov/osweroe1/content/rmp/index.htm. The RMP Reporting Center can be contacted at: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.

b. Submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.

[40 CFR 68]

Subsection A. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
001	Biomass fuel delivery, preparation, storage and handling

The biomass fuel delivery, preparation, storage and handling system consists of: three truck dumpers; two sets of screens and hogs (i.e., machines used to size wood chips); and automatic and manual stacker/reclaimers to maintain on average a 15 to 20 day supply of biomass fuel for the BFB boiler based on full load operation and average biomass fuel moisture content. The GREC biomass fuels are initially chipped/ground and processed at offsite locations and then transported to the site by truck. There are between 130 and 150 fuel truck deliveries per day based on the maximum BFB boiler biomass fuel consumption rate/average moisture content and a 6-day-per-week delivery schedule. During peak delivery periods, the delivery facilities are capable of unloading 24 truckloads of biomass fuel per hour. The GREC biomass fuel handling system includes scales to weigh each truck entering and departing the facility to determine the delivered fuel weight. The maximum designed hourly biomass processing rate is 600 tons per hour (TPH) with a maximum designed yearly rate of 1,395,030 tons per year (TPY).

There are four biomass storage piles as described below:

- Storage Pile No.1: Storage Pile No. 1 is a kidney shaped pile that is formed with an automatic stacker/reclaimer. The pile is up to 60 feet (ft) high and has a storage capacity of approximately 74,800 cubic yards (yd^3) of fuel.
- Stock Pile No. 1: Stock Pile No. 1 is a conical shaped pile that is fed with a fixed stacker, which includes a telescoping chute to minimize the distance the fuel will drop when the pile is empty. The pile is up to 60 ft high and has a storage capacity of approximately 8,500 yd^3 of fuel.
- Storage Pile No. 2: Storage Pile No. 2 is approximately 35 ft high with a storage capacity of approximately 162,000 yd^3. Rolling stock (i.e., a bulldozer or front-end loader) are used to remove fuel from Stock Pile No.1 and deliver it to Storage Pile No. 2.
- Saw Dust Pile: In addition to the chipped/ground biomass fuel, moist sawdust is received at the site. Sawdust is delivered with self-unloading trucks and deposited in an open area adjacent to Storage Pile No.2 in a fourth, small pile. Front-end loaders are used to reclaim sawdust.

The biomass fuel delivery, preparation, handling and storage system also includes the following equipment:

- Scales: Truck scales to weigh each biomass fuel delivery truck arriving and departing the facility to determine the weight of delivered biomass.
- Screen/Hog Building: A fully enclosed building containing surge bins, size disk screens, and hogging equipment.
- Truck Dumpers: Three drive-through truck dumpers with receiving hoppers.
- Conveyors: Six conveyors to transport the biomass fuel from the truck dumpers to the biomass fuel handling and storage system. The conveyor entering the screen/hog building also has a metal detector and self-cleaning magnetic separator.
- Surge Bins: Two surge bins and two reclaimers within the screen/hog building to accept the biomass fuel from the conveyors from the truck dumpers.
- Sizing Discs: Two sizing discs within the screen/hog building to screen any oversized biomass fuel and then send the oversize fuel to the hogs to be reduced in size.
- Hogs: Two hogs within the screen/hog building to reduce the size of any oversized biomass fuel.
- Stacker/Reclaimer: A stacker/reclaimer system to place and reclaim biomass fuel from Storage Pile No.1.
- Telescoping Chute: A telescoping chute to place biomass fuel in Stock Pile No.1.

- Conveyors: Two conveyors to transport the biomass fuel to the stacker/reclaimer used for Storage Pile No.1 and the telescoping chute used for Stock Pile No.1. Five conveyors used to transport the biomass fuel from Storage Pile No.1 and Storage Pile No.2 to the BFB boiler metering bins. Scales and magnetic separators will be included in some of the conveyors.
- Metering Bins: Two BFB boiler biomass fuel metering bins to provide storage of biomass fuel sufficient for approximately 45 minutes of boiler operation with the bins equipped with bin vent filters to control of PM emissions.

Essential Potential to Emit (PTE) Parameters

A.1. Hours of Operation. This emissions unit may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE), F.A.C., Permit No. 0010131-003-AC (PSD-FL-411B)]

A.2. Clean Woody Biomass: The fuel to be received, handled, stored and processed shall consist of clean, untreated woody biomass as defined below. The permittee is specifically prohibited from accepting biomass in the form of construction and demolition (C&D) debris. The BMP plan referenced in **Specific Condition A.4.** of this subsection shall be followed.

Fuel Type	Description
In-forest residue and slash	Tops, limbs, whole tree material and other residues from soft and hardwoods that result from traditional silvicultural harvests.
Mill residue	Saw dust, bark, shavings and kerf waste from cutting/milling whole green trees; fines from planning kiln-dried lumber; wood waste material generated by primary wood products industries such as round-offs, end cuts, sticks, pole ends; and reject lumber as well as residue material from the construction of wood trusses and pallets.
Pre-commercial tree trimmings and understory clearings	Tops, limbs, whole tree material and other residues that result from the cutting or removal of certain, smaller trees from a stand to regulate the number, quality and distribution of the remaining commercial trees; and forest understory which includes smaller trees, bushes and saplings.
Storm, fire and disease debris	Tops, limbs, whole tree material and other residues that are damaged due to storms, fires or infectious diseases.
Urban wood waste	Trees and other clean, woody matter generated by households, landscaping contractors or power line/roadway clearance contractors that have been cut down for land development, right-of-way clearing or general landscape management purposes.
Recycled industrial wood	Wood derived from used pallets packing crates; and dunnage disposed by commercial or industrial users.
Supplementary fuel material	Clean agricultural residues (i.e., rice hulls, straw, etc.; no animal wastes or manure); and whole tree chips and pulpwood chips.

[Permit No. 0010131-003-AC (PSD-FL-411B); Rule 62-4.070(3), F.A.C. Reasonable Assurance; Final Order dated 12/27/2010]

Control Technology

A.3. Air Pollution Control Equipment: To minimize fugitive PM, woody biomass conveyors are enclosed where practical.

a. *Screen/Hog Building Baghouse*: A baghouse is used to control PM emissions from the Screen/Hog building. A screw conveyor is installed to take the PM collected in the baghouse to the conveyor taking the biomass fuel to the biomass fuel handling and storage system.

b. *Metering Bin Vent Filters*: Bin vent filters is used to control PM emissions from the metering bins for the BFB boiler.

{Permitting Note: One small section of the conveyance belt of the conveyors near the truck dumpers shall provide for visible inspection from above so that woody biomass that does not meet ***Specific Condition A.4.*** *of this subsection can be removed.}*

[Permit No. 0010131-003-AC (PSD-FL-4111B); and Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

A.4. BMP Plan: The revised BMP included in Appendix BMP of Section VI of this permit shall be utilized to minimize fugitive PM emissions from receiving, handling, storage and processing of woody biomass. Best management practices shall be utilized to reduce the potential for spontaneous combustion of stored woody biomass and odors. This plan also includes quality control and assurance (Q&A) procedures to ensure woody biomass delivered by vendors and suppliers to the GREC facility meets the requirements given in **Specific Condition A.2.** of this subsection. [Permit No. 0010131-003-AC (PSD-FL-411B); and Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

A.5. Paved Roadways and Gravel Areas: Fugitive dust emissions from the plant's paved roadways and gravel areas shall be controlled in accordance with **Section B of Appendix BMP** in Section VI of this permit. [No. 0010131-003-AC (PSD-FL-411B); and Rules 62-4.070, F.A.C. Reasonable Assurance and 62-296.320, F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for **Specific Condition A.6.** of this subsection is based on the specified averaging time of the applicable test method.

A.6. Opacity: As determined by EPA Method 9, there shall be no visible emissions (VE) greater than 10% opacity, except for one 6 minute period no greater than 20% from the outlets of the drop points and transfer points associated with this emission unit. VE from the Screen/Hog building baghouse and bin vent filters of the metering bins shall be no greater than 5% opacity.
[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-212.400(5)(c), 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

Test Methods and Procedures

A.7. Test Method. When required, tests shall be performed in accordance with the following reference method:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above method is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C.; and Permit No. 0010131-003-AC (PSD-FL-411B)]

A.8. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in **Appendix TR, Facility-Wide Testing Requirements**, of **Section VI** of this permit. [Rule 62-297.310, F.A.C.]

A.9. Annual VE Compliance Tests. During each federal fiscal year (October 1st to September 30th), the outlets of the Screen/Hog building baghouse and the bin vent filters of the metering bins associated with

this emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in **Specific Condition A.6.** of this subsection. [Rules 62-210.300(2)(a) and 62-297.310(7), F.A.C.]

A.10. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in **Appendix TR** of **Section VI** of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

Recordkeeping and Reporting Requirements

A.11. Other Reporting Requirements. See **Appendix RR, Facility-Wide Reporting Requirements** of **Section VI** of this permit for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

Subsection B. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
002	Nominal net 100 MW BFB, biomass fueled boiler.

The boiler is a woody biomass fueled bubbling fluidized bed (BFB) boiler wherein wood is combusted in a bed of hot sand. The heat from the exhaust is recovered to generate superheated steam to generate 100 MW (nominal, net) of electricity in a steam turbine electrical generator (STEG). The primary fuel will be clean woody biomass as described in **Appendix BMP of Section VI** of this permit. Natural gas is used as a startup fuel for the boiler. The maximum heat input capacity is 1,358 MMBtu per hour (4 hour average basis). The steam production capability is between 650,000 to 930,000 pounds per hour (lb/hr). The maximum heat input capacity using natural gas is 341 MMBtu/hr during startup.

With an as-built stack of 12 feet (ft) in diameter and 230 ft tall. Exhaust flue gas exit the stacks at the following approximate conditions: an exit temperature of 310 degrees Fahrenheit (°F) and a volumetric flow rate of 520,600 actual cubic feet per minute (acfm). Emissions of carbon monoxide (CO,),nitrogen oxide (NO_X) and sulfur dioxide (SO_2) are monitored and recorded by continuous emissions monitoring systems (CEMS), while opacity is monitored and recorded by a continuous opacity monitoring system (COMS).

Applicable Federal Standards

B.1. NSPS 40 CFR 60, Subpart Da. This unit is subject to NSPS Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978 {72 Federal Register (FR) 32722, June 13, 2007, as amended at 78 FR 24082, Apr. 24, 2013}, because it has a maximum heat input capacity greater than 250 MMBtu/hr from the fossil fuels (natural gas) combusted. Since construction of the GREC facility commenced on April 19, 2011, the BFB boiler is subject to the emission limits in Subpart Da for units that commenced construction after February 28, 2005 and before May 4, 2011. Excerpts of the applicable requirements from Subpart Da are contained in this subsection while the entire subpart is provided in **Appendix Da in Section VI** of this permit. [NSPS 40 CFR 60, Subpart Da]

{Permitting Note: The requirements of Subpart Da are provided *for clarity and convenience in this subsection. However, if all the applicable requirements from the subpart are not contained in this subsection, the permittee is still subject to the omitted requirements.}*

B.2. NESHAP 40 CFR 63, Subpart DDDDD. This unit is subject to NESHAP Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Since construction of the GREC facility commenced after June 4, 2010, the BFB boiler is considered a new source under Subpart DDDDD. Excerpts of the applicable requirements from Subpart DDDDD are contained in this subsection while the entire subpart is provided in **Appendix DDDDD in Section VI** of this permit. [NESHAP 40 CFR 63, Subpart DDDDD]

{Permitting Note: The requirements of Subpart DDDDD are provided *for clarity and convenience in this subsection. However, if all the applicable requirements from the subpart are not contained in this subsection, the permittee is still subject to the omitted requirements.}*

Essential Potential to Emit (PTE) Parameters

B.3. Authorized Fuels. The BFB boiler is authorized to combust as its primary fuel clean woody biomass as defined in **in Appendix BMP in Section VI** of this permit. In addition, the boiler is authorized to combust natural gas as a startup fuel.
[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C., and NSPS, Subpart Da]

B.4. Heat Input Rate from All Fuels. The maximum heat input capacity from biomass and natural gas is 1,358 MMBtu per hour (4 hour average basis). [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

B.5. Heat Input from Fossil Fuels. The maximum heat input capacity to combust natural gas on a steady state basis during boiler startup is limited to 341 MMBtu/hr. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

B.6. Operational Hours. The hours of operation of this emission unit are not restricted (8,760 hours/year). [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3) and 62-210.200(PTE)]

Control Technology

B.7. Air Pollution Control Equipment. To comply with the emission standards of this permit, the permittee shall operate and maintain the following BFB boiler add-on air pollution control equipment.

a. *Fabric Filter Baghouse*: The permittee shall operate and maintain a fabric filter baghouse to control particulate matter (PM) and visible emissions (VE).

b. *Selective Catalytic Reduction (SCR) System:* The permittee shall operate, and maintain an ammonia (NH_3) based SCR system including reagent storage tank, pumps, metering system, injection grid, reactor and catalyst to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SCR shall be brought on line in accordance with the SCR manufacturer's procedures and guidelines and will be utilized whenever the boiler is in operation.

c. *In Duct Sorbent Injection System (IDSIS):* An IDSIS including a baghouse, sorbent storage silo, pumps, metering and injection equipment shall be operated and maintained to control SO_2 emissions and hazardous air pollutants (HAP) acid gases such as hydrogen chloride (HCl) and hydrogen fluoride (HF) to the emission standards specified **Specific Condition B.10** in this subsection. As part of this IDSIS, the alkaline sorbent silo is equipped with a bin vent filter to control PM emissions. The IDSIS relies on the presence of alkaline fly ash and shall be augmented as necessary by the use of injected trona (or equivalent). The SO_2 CEMS output data expressed in lb/hr averaged over a 24-hour period shall be reviewed by trained plant personnel on a daily and monthly basis to determine required operation of, or adjustment to the alkaline sorbent injection augmentation to ensure the SO_2 emission standards will be maintained.

[Permit No. 0010131-003-AC (PSD-FL-411B); NSPS Subpart Da; Rule 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.; Final Order dated 12/27/2010]

B.8. Circumvention. The permittee shall not circumvent the air pollution control equipment or allow the emissions of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

B.9. Ammonia Storage Tank. The aqueous ammonia, containing 19% ammonia by volume is stored in one outdoor 15,000 gallon tank designed and fabricated in accordance with U.S. Department of Labor Chapter 29, Part 1910.111, Code of Federal Regulations (CFR), American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, ANSI K 61.1, and applicable requirements of Chapter 62-762, F.A.C., Above Ground Storage Tank (AST) Systems.
[Permit No. 0010131-003-AC (PSD-FL-411B) and Rule 62-4.070(3), F.A.C.]

Emission Limitations and Standards

{Permitting Note: The attached Table 1, Summary of Air Pollutant Standards, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

Unless otherwise specified, the averaging time for **Specific Condition B.10.** of this subsection are based on the specified averaging time of the applicable test method.

B.10. Emission Limits. Emissions from the BFB boiler shall not exceed the following standards.

Parameter	Limit	Basis	Compliance
NO_X [a]	1.0 lb/MWH (gross basis)	NSPS Subpart Da	30-boiler operating day rolling average basis by CEMS
	0.070 lb/MMBtu	Applicant Request	24-hour rolling by CEMS
	416.4 TPY	Emission Cap	12-month, rolled monthly by CEMS
SO_2 [b]	1.4 lb/MWH (gross basis)	NSPS Subpart Da	30-boiler operating day rolling average basis by CEMS
	0.029 lb/MMBtu	Applicant Request	24-hour rolling by CEMS
	170.7 TPY	Emission Cap	12-month, rolled monthly by CEMS
SAM [c]	1.4 lb/hr	Rule 62-4.070(3), F.A.C.	Annual Stack Test
CO [d]	0.12/0.08 lb/MMBtu	BACT	30-day rolling by CEMS
	310 ppmvd @3% O_2	NESHAP Subpart DDDDD	
HCl [e, f]	2.22 lb/hr	Applicant's Request	Annual Stack Test
	0.022 lb/MMBtu	NESHAP Subpart DDDDD	Stack Tests as Required by NESHAP Subpart DDDDD
HF [e]	2.22 lb/hr	Applicant's Request	Annual Stack Test
Mercury [f]	8.0 x 10^{-7} lb/MMBtu	NESHAP Subpart DDDDD	Stack Tests as Required by NESHAP Subpart DDDDD
PM/PM_{10} (filterable) [g]	0.0098 lb/MMBtu	BACT, Subpart Da NESHAP Subpart DDDDD	Annual Stack Test
VE [h]	10% Opacity (20% once/hr)	BACT	6-minute blocks by COMS
VOC [i]	0.010/0.009 lb/MMBtu	BACT	Annual Stack Test
NH_3 Slip [j]	10 ppmvd @ 7% O_2	Rule 62-210.650, F.A.C. Rule 62-4.070(3), F.A.C.	Annual Stack Test
Heat Input Rate	1,358 MMBtu/hr	Rule 62-210.200(PTE), F.A.C.	4-hour average, by 40 CFR 75, App. F

a. lb/MWH means pounds per MW-hour (gross basis). lb/MMBtu means pounds per million Btu heat input. Emission cap for NO_X ensures that GREC will not trigger PSD for this pollutant.
b. Emission cap for SO_2 ensures that GREC will not trigger PSD for this pollutant.
c. SAM mass rate emission limit provides reasonable assurance that annual emissions will be less than 7 TPY and PSD is not triggered for this pollutant.
d. A CO limit of 0.12 lb/MMBtu on a rolling 30-day average applies from the startup of boiler operation through 360 calendar days after certification of the CO-CEMS. A CO limit of 0.08 lb/MMBtu applies thereafter. The NESHAP limit of 310 ppmvd @3% O_2 applies from the initial operation of the boiler.
e. The hourly limits for HF and HCl are imposed at the Applicant's request. Compliance will be demonstrated with annual stack tests.
f. Hg and HCl limits for Subpart DDDDD compliance. However, if the performance tests for at least 2 consecutive years show that the emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the BFB boiler or air pollution

control equipment that could increase emissions, GREC may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

g. Filterable (F) fraction as measured by EPA Method 5. The Subpart DDDDD 0.0098 lb/MMBtu limit will ensures compliance with the previous BACT and NSPS Subpart Da limit of 0.015 lb/MMBtu.

h. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%. Meeting this opacity standard provides assurance that the NSPS Subpart Da standard of no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity is met.

i. A VOC limit of 0.010 lb/MMBtu applies from the startup of boiler operation through 360 calendar days after certification of the CO-CEMS. A VOC limit of 0.009 lb/MMBtu applies thereafter.

j. Ammonia (NH3) slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O2).

[Permit No. 0010131-003-AC (PSD-FL-411B); NSPS Subpart Da; Rule 62-4.070(3), 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.; Final Order dated 12/27/2010; NESHAP 40 CFR 63, Subpart DDDDD]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

B.11. Malfunction Notifications. In case of excess emissions resulting from malfunctions, permittee shall notify the Compliance Authority. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the permittee's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the permittee shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

B.12. Operating Procedures. The emission standards established by this permit rely on "good combustion practices" (GCP) and add-on control equipment to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the BFB boiler and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include GCP as well as methods of minimizing excess emissions. [Rule 62-4.070(3), F.A.C.]

B.13. Excess Emissions. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.

a. Startup: Excess emissions resulting from a cold startup of the BFB boiler shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 19 hours unless specifically authorized by the Department for longer duration.

{Permitting note: A cold start-up of the BFB boiler is a complex procedure done infrequently and has an extended duration, because it is necessary to first heat the sand bed of the BFB boiler, bring the boiler up to its operational temperatures and pressures, and start-up the steam turbine-electric generator.}

b. Shutdown: Excess emissions resulting from shutdown of the BFB boiler shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 3 hours in any 24 hour period unless specifically authorized by the Department for longer duration.

c. Duration: The combined duration of excess emissions from the BFB boiler during startup and shutdown events shall not exceed 340 hours during any consecutive 12 month period.

d. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

e. Emission Limit Compliance and Excess Emission: Data exclusions are allowed for calculation of the 24-hour SIP-based NO_X and SO_2 limits and the 30-day SIP-based CO limit.

f. NO_X and SO_2 Emission Caps: No data exclusions are permissible when calculating the 12-month rolling total emissions of NO_X and SO_2 emissions caps given in **Specific Condition B.10.** of this subsection.

g. Opacity: During startup, shutdown and malfunctions, the stack opacity shall not exceed 20% based on 6-minute block averages, except for one 6-minute block per hour that shall not exceed 27% opacity.

[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-210.700(5), 62-210.200(PTE), 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

B.14. NSPS and NESHAP Requirements. NSPS Subpart Da emission limits apply at all-times except during periods of startup, shutdown, or malfunction. NESHAP Subpart DDDDD standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with the Work Practice Standards of Table 3 to the subpart. [§60.48Da(a) and §63.7500(f)]

Monitoring of Operations

B.15. CAM Plan. This emissions unit is subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C. [40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

B.16. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). Records shall be maintained on site and made available upon request. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-212.400 (BACT) and 62-210.200(PTE), F.A.C.]

B.17. Pressure Drop: The permittee shall maintain and calibrate a device which continuously measures and records the pressure drop across each baghouse compartment controlling the PM emissions from the BFB boiler. Records shall be maintained on site and made available upon request. [Permit No. 0010131-003-AC (PSD-FL-411B); Rule 62-4.070(3) and 62-212.400 (BACT) F.A.C.]

B.18. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems on the BFB boiler baghouse including keeping records of the systems measurements. Baghouse leak detection records shall be kept on site and made available upon request. The bag leak detection system shall be operated according to §63.7525(j). The BFB boiler baghouse shall be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period. [Permit No. 0010131-003-AC (PSD-FL-411B); Rule 62-4.070(3) and 62-212.400 (BACT) F.A.C.; NESHAP Subpart DDDDD, Table 4]

NSPS 40 CFR 60, Subpart Da Compliance Provisions

B.19. NSPS Excess Emissions. For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the particulate matter emission standards under 40 CFR 60.42Da, the SO_2 emission standards under 60.43Da, and the NO_X emissions standards under 40 CFR 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. [40 CFR 60.48Da(a)]

B.20. Compliance Averages. For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by calculating the arithmetic average of all hourly emissions rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. [40 CFR 60.48Da(d)]

B.21. Compliance Determinations NO_X. To show compliance with the 1.0 lb/MWH (gross) NO_X emission standard, the owner or operator shall calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. [40 CFR 60.48Da(i)]

B.22. Compliance Determinations SO_2. To show compliance with the 1.4 lb/MWH (gross) SO_2 emission standard, the owner or operator shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. [40 CFR 60.48Da(m)]

B.23. Compliance Determination Opacity. To show compliance with the opacity emission standard, the owner or operator of an affected facility subject to the opacity standard given in **Specific Condition 10** of this subsection shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in §60.49Da(a), as applicable to the affected facility. [40 CFR 60.48Da(q)]

B.24. Insufficient Data. If the owner or operator has not obtained the minimum quantity of emission data as required under 40 CFR 60.49Da, compliance of the affected facility with the emission requirements under 40 CFR 60.43Da and 60.44Da for the day on which the 30-day period ends may be determined by the Administrator following the applicable procedures in section 7 of Method 19. [40 CFR 60.48Da(h)]

NESHAP 40 CFR 63, Subpart DDDDD Compliance Provisions

B.25. Demonstration of Compliance. You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a CEMS, COMS, continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for HCl, mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emissions limit listed in Tables 1, 2, or 11 through 13 to this subpart. [§63.7505(c)]

B.26. Monitoring Plan. If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs §63.7505(d)(1) through (4) of Subpart DDDDD for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f). [§63.7505(d)]

B.27. Annual Compliance. You must conduct all applicable performance tests according to §63.7520. on an annual basis, except as specified in paragraphs §63.7515(b) through (e), (g), and (h) of Subpart DDDDD. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs §63.7515(b) through (e), (g), and (h) of Subpart DDDDD. [§63.7515(a)]

B.28. HCl Compliance. If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of Subpart DDDDD and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter. [§63.7525(m)]

B.29. Subpart DDDDD Work Practice Standards. GREC shall conduct a tune-up of the BFB boiler every 5 years as specified in §63.7540(a)(10). [NESHAP Subpart DDDDD, Table 3, Item 1]

{Permitting note: The BFB boiler is equipped with a continuous oxygen trim system that maintains an optimum air to fuel ratio}

B.30. 40 CFR 63 General Provisions. Table 10 from Subpart DDDDD shows which parts of the General Provisions in §§63.1 through 63.15 apply to the GREC boiler. [§63.7565]

Continuous Emission Monitors

B.31. Continuous Monitoring Requirements. The permittee shall install, calibrate, maintain and operate CEMS, a COMS and a diluent monitor to measure and record the emissions of SO_2, NO_X, CO, opacity and carbon dioxide (CO_2) or O_2, respectively, from the BFB boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based and COMS-based emission standards in **Specific Condition B.10.** of this subsection Within one working day of discovering emissions in excess of a SO_2, NO_X or CO standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority. The permittee shall comply with the CEMS requirements specified in **Appendix CEMS of Section VI** of this permit.

a. *SO_2 CEMS*: The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subpart Da in 40 CFR 60 and Subparts F and G in 40 CFR 75.

b. *NO_X CEMS*: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Recordkeeping and reporting shall be conducted pursuant to Subpart Da in 40 CFR 60 and Subparts F and G in 40 CFR 75.

c. *CO CEMS*: The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

d. *COMS*: In accordance with 60.48Da(o)(2)(i) the permittee shall install, calibrate, operate and maintain a COMS to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

e. *Diluent Monitor:* The O_2 or CO_2 content of the flue gas shall be monitored at the locations where CO, SO_2 and NO_X, are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Permit No. 0010131-003-AC (PSD-FL-411B); Rule 62-4.070(3), and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Subpart Da and Appendices; and 40 CFR 75, Subpart F and G]

NSPS 40 CFR 60, Subpart Da CEMS Requirements

B.32. SO_2 Requirements. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere.

a. If the owner or operator has installed and certified a SO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section.

b. The SO_2 CEMS shall be operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

[§60.49Da(b)(1) and (4) and (e), Emission Monitoring]

B.33. NO_X Requirements. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_X emissions discharged to the atmosphere. If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this Subpart Da, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

a. The NO_X CEMS shall be operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

[§60.49Da(c) and (e) Emission Monitoring]

NESHAP 40 CFR 63, Subpart DDDDD CEMS Requirements

B.34. CO CEMS. If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 of Subpart DDDDD, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain CEMS for CO and oxygen according to the procedures in paragraphs §63.7525(a)(1) through (7) of Subpart DDDDD. [§63.7525(a)]

B.35. Monitoring Plan. You must monitor and collect data according to section §63.7535 of Subpart DDDDD and the site-specific monitoring plan required by **Specific Condition B.26**. [§63.7535(a)]

B.36. Operation of the Monitoring System. You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable. [§63.7535(b)]

B.37. Monitoring System Malfunctions. You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system. [§63.7535(c)]

B.38. Failure to Collect Data. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report. [§63.7535(d)]

B.39. Demonstration of Continuous Compliance. You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 in Subpart DDDDD, the work practice standards in Table 3 in Subpart DDDDD, and the operating limits in Table 4 in Subpart DDDDD that applies to you according to the methods specified in Table 8 in Subpart DDDDD and paragraphs §63.7540 (a)(1) through (19) of Subpart DDDDD. [§63.7540(a)]

B.40. Emission Exceedance. You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 in Subpart DDDDD that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in Subpart DDDDD. These deviations must be reported according to the requirements in **Specific Condition B.54**. [§63.7540(b)]

B.41. Work Practice Standards. For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart. [§63.7540(d)]

Test Requirements

B.42. Subpart Da PM Testing Requirements. In conducting the performance tests to determine compliance with the PM emissions limits in §60.42Da, the owner or operator shall meet the requirements specified below.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in §60.42Da as specified in paragraphs (1)(i) through (ii) of this section.

(i.) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii.) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

A. The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ±14 °C (320 ±25 °F).

B. For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(2) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

[§60.50Da(b)(1) and (3) Compliance Determination Procedures and Methods.]

B.43. Subpart DDDDD Performance Tests. You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

a. You must conduct each performance test according to the requirements in Table 5 of Subpart DDDDD

b. You must conduct each performance test under the specific conditions listed in Tables 5 and 7 of Subpart DDDDD. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 of Subpart DDDDD.

c. You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 of Subpart DDDDD.

d. To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR 60, appendix A-7 of this chapter to convert the measured PM concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to lb/MMBtu heat input emission rates.

e. Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[§63.7520]

B.44. Boiler Heat Input Rate Calculation. Section 5 of Appendix F of 40 CFR 75 provides a methodology for calculation of the heat input rate to a boiler using F-Factors. The applicable portions of 40 CFR 75 for the calculation of the heat input rate to the biomass BFB boiler at the GREC facility is contained in **Appendix F of Section VI** of this permit. This procedure shall be used to calculate the heat input rate in MMBtu/hr to the BFB boiler when using clean woody biomass as its primary fuel and natural gas as a startup fuel. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3) and 62-212.400 (BACT) F.A.C.; and 40 CFR 75, Appendix F]

B.45. Annual Stack Tests. In accordance with test methods specified in this permit, the BFB boiler stack shall be tested during each federal fiscal year (October 1st to September 30th)to demonstrate compliance with the emission standards for NH_3 slip, PM (F), VOC, SAM, HCl (in units of lb/hr and lb/MMBtu), HF (in units of lb/hr) and opacity. Compliance stack tests for HCl (in units of lb/MMBtu) shall be conducted as required by NESHAPs Subpart DDDDD. Tests shall be conducted between 90 and 100% of the maximum heat input rate when firing woody biomass fuel. CEMS data for CO, NO_X and SO_2 along with COMS data for opacity shall be reported for each run of the required tests for NH_3, VOC, SAM and PM. The BFB boiler was required to conduct initial stack tests for NH3, filterable PM (F), VOC, SAM, opacity, HCl, and HF. The Department may require the permittee to repeat some or all of these initial

stack tests after major replacement or major repair of any air pollution control or process equipment. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-212.400(5)(c), 62-212.400 (BACT) and 62-297.310(7)(a) and (b), F.A.C.; and 40 CFR 60.8]and 40 CFR 60.8]

Test Methods and Procedures

{Permitting Note: The attached Table 2, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.46. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

EPA Method	Description of Method and Comments
CTM-027	Measurement of NH_3 Slip
320	Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
5, 5B, 17	Measurement of PM
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
8A	Determination of Sulfuric Acid and Sulfur Dioxide Emissions
9	Visual Determination of the Opacity
10	Measurement of CO Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{For concurrent use with EPA Method 25A to deduct emissions of methane and ethane from the total hydrocarbon (THC) emissions measured by Method 25A.}*
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)
26, 26A	Determination of HCl and HF Emissions from Stationary Sources
29	Metals Emissions from Stationary Sources
30B	Determination of Mercury from Coal-Fired Combustion Sources Using Carbon Sorbent Traps
201, 201A	Measurement of PM_{10}
202	Determining Condensable Particulate Emissions from Stationary Sources
1. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html . The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C.	

[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A; and Final Order dated 12/27/2010]

B.47. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

Recordkeeping and Reporting Requirements

B.48. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

B.49. Stack Test Reports. In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (MMBtu/hour), calculated authorized fuels firing rate (tons/hour and cubic feet per minute as appropriate), and emission rates (ammonia (NH_3) slip in ppmvd @ 7% oxygen; PM (F), VOC, SAM, opacity, HF and HCl in appropriate units). The annual stack test reports shall include the hourly emission rates for HF and HCl. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-210.300(2)(a), 62-297.310(7)(a), 62-4.070(3) and 62-212.400 (BACT) F.A.C.]

B.50. Monthly Operations Summary. By the tenth calendar day of each month, the permittee shall record the following for each fuel used in the BFB biomass boiler in a written or electronic log for the previous month of operation: hours of operation, tons of clean woody biomass and cubic feet of natural gas; pounds of steam per month; total heat input rate; and the updated 12-month rolling totals for each of these operating parameters. In addition, the hourly heat input rate to the BFB biomass boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3) and 62-212.400 (BACT) F.A.C.]

B.51. Quarterly CO, NO_X, SO_2, and Opacity Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2 and opacity emissions including periods of startups, shutdowns, malfunctions, and CEMS and COMS systems monitor availability for the previous quarter. If NO_X and SO_2 CEMS data or opacity COMS data is excluded from a compliance determination during the quarter due to a malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix RR of this permit for the reporting format. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-4.130, 62-212.400 (BACT) and 62-213.440(1), F.A.C.]

B.52. Subpart Da Reporting Requirements. For SO_2, NO_X, PM, and NO_X plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator as follows.

(a) For SO_2 and NO_X the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average SO_2 and NO_X emission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(b) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (Eo*) and the upper confidence limit for the mean inlet emission rate (Ei*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (Eo*) and the allowable emission rate (Estd) as applicable.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) and conducting performance tests using Method 9 of appendix A-4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (1)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified below.

(i.) Dates and time intervals of all opacity observation periods;

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

(iii.) Copies of all visible emission observer opacity field data sheets.

(d) For any periods for which opacity, SO_2 or NO_X emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(f) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(g) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(h) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

[§60.51Da Reporting Requirements, (a), (b), (c), (d), (f), (h), (i), (j) and (k)]

B.53. Subpart Da Recordkeeping Requirements. The owner or operator of an affected facility subject to the opacity limits that elects to monitor emissions according to the requirements in §60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs below.

(a) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (a)(1) through (3) of this section.

1. Dates and time intervals of all opacity observation periods;
2. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
3. Copies of all visible emission observer opacity field data sheets;

(b) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(1) through (4) of this section.

1. Dates and time intervals of all visible emissions observation periods;
2. Name and affiliation for each visible emission observer participating in the performance test;
3. (Copies of all visible emission observer opacity field data sheets; and
4. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(c) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[§60.52Da Recordkeeping Requirements, (b) and (b)]

B.54. Subpart DDDDD Reports. You must submit each report in Table 9 in Subpart DDDDD that applies to you. Reports shall be submitted meeting the requirements of §63.7550(b), (c), (d), (e) and (h) of Subpart DDDDD. [§63.7550]

B.55. Subpart DDDDD Recordkeeping. You must keep records according to paragraphs §63.7555(a)(1) and (2) of Subpart DDDDD. You must keep the records required in Table 8 in 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 that applies to you. For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 in Subpart DDDDD, you must also keep the applicable records in paragraphs§63.7555(d)(1) through (11) of Subpart DDDDD. [§63.7555(a), (c), and (d)]

Other Requirements

B.56. NO_X and SO_2 Emission Caps. ***By April 1st of each year***, the permittee shall report the BFB boiler's annual NO_X and SO_2 emissions in the Annual Operating Report to demonstrate compliance with the annual NO_X and SO_2emissions caps of 416.4 and 170.7 TPY, respectively, based on CEMS data. If the boiler annual NO_X or SO_2 emission caps are exceeded, the permittee shall notify the Compliance Authority within three working days of discovery. [Permit No. 0010131-003-AC (PSD-FL-4111B); Rules 62-4.070(3) and 62-212.400 (BACT) F.A.C.]

GREC Settlement Agreement

B.57. **Not federally Enforceable.** Settlement Agreement Requirements: Appendix AS in Section VI of this permit contains additional air quality commitments from the settlement agreement (DOAH Case No. 10-7281) reached between GREC and non-Department parties.

{Permitting Note: The provisions in this agreement are not required by any federal or state laws and are not federally enforceable; however, the agreement is enforceable by the participating parties of the agreement.}

Subsection C. The specific conditions in this section apply to the following emissions unit:

EU ID No.	Brief Description
003	Ash handling, storage and shipment

Approximately two thirds of ash created by the combustion of biomass fuel will exit the BFB boiler as fly ash with the remaining third leaving as bottom ash. The design maximum process throughput rates are 27,594 TPY of fly ash and 13,140 TPY of bottom ash.

- *Fly Ash*: Fly ash from the boiler convective pass and fabric filter baghouse hoppers is collected dry and transported pneumatically to a single fly ash storage silo by means of two vacuum blowers. The transferred fly ash is first passed through a receiver/collector that separates the fly ash from the conveying air stream. The separated fly ash then flows through an air lock valve into the storage silo, which shall be vented through a baghouse for control of PM emissions. From the silo, the fly ash is then either stabilized using water in a pug mill or loaded dry into a receiving truck. For the fly ash stabilization case, fly ash and water is mixed in a pug mill and then transferred via a chute into covered trucks and then hauled offsite for reuse or disposal. During the dry transfer of fly ash, an enclosed process is utilized to transfer ash from the silo through a chute into sealed trucks.
- *Bottom Ash*: Bottom ash from the bed primarily consists of noncombustible material (i.e., rocks, glass, sand, metal) contained in the biomass fuel. The coarse bottom ash is removed from the BFB boiler through ash hoppers and chutes. Coarse material fall from the bed into the ash hoppers, which form a gas tight seal with the furnace bottom. The coarse material is then sieved in a rotating screen prior to being conveyed to the bottom ash container. The contents of the bottom ash container is taken offsite for disposal in a properly licensed landfill.

{Permitting Note: In the following discussion of the ash handling, storage and shipment emission unit, the term baghouse as a PM control device can also mean bin vent filter. A bin vent filter employs similar filtration technology to a baghouse.}

Equipment

C.1. Equipment. The permittee is authorized to operate and maintain an ash handling, storage and shipment emission unit, which consists of ash (fly and bottom) handling, storage and shipment systems containing the following equipment:

a. *Fly Ash Handling*: The fly ash handling system consisting of totally enclosed hoppers and drop points associated with the collection and transfer of fly ash from the baghouse used to control PM emissions from the BFB biomass boiler to a storage silo.

b. *Fly Ash Storage*: A fly ash storage system consisting of a storage silo and baghouse to control PM emissions.

c. *Pug Mill*: A pug mill to stabilize the fly ash with water before loading into a covered truck for shipment off site.

d. *Fly Ash Shipment*: The fly ash shipment system consisting of the drop points, conditioner and chutes associated with the transfer of the wet or dry fly ash from the storage silo to trucks for shipment.

e. *Bottom Ash Handling and Shipment*: The bottom ash handling and shipment system consisting of the hoppers, drop points, collecting conveyor and transfer conveyor associated with the collection, transfer and shipment of bottom ash from the BFB biomass boiler.

[Permit No. 0010131-003-AC (PSD-FL-411B)]

Essential Potential to Emit (PTE) Parameters

C.2. Hours of Operation. The hours of operation of this emissions unit are not limited (i.e., unrestricted at 8,760 hours per year).

C.3. Fly Ash Handling and Storage. The fly ash handling system has a maximum design transfer rate of 3.2 TPH with a maximum annual design transfer rate of 27,594 TPY.

C.4. Bottom Ash Handling. The bottom ash handling system has a maximum design transfer rate of 1.5 TPH with a maximum annual design transfer rate of 13,140 TPY.

C.5. Ash Handling, Storage and Shipment. The overall ash handling, storage and shipment system (EU-003) has a maximum annual design transfer rate of 40,734 TPY.

[Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

Emission Limitations and Standards

C.6. VE Standard. As determined by EPA Method 9, there shall be no visible emissions greater than 10% opacity, except for one 6 minute period no greater than 20% from the bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes and dust collectors.
[Rules 62-4.070, 62-212.400 (BACT), F.A.C.]

C.7. Fly Ash Silo Baghouse PM Emission Standard.: PM emissions from the baghouse of the fly ash silo shall not exceed 0.015 gr/dscf. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070(3), 62-212.400 (BACT), 62-210.200(PTE) and 62-4.070, F.A.C.]

C.8. Baghouse PM Standard by Opacity Measurement. A visible emission reading of 5% opacity or less may be used to demonstrate compliance with the PM emission standard in **Specific Condition C.7.** above**.** A visible emission reading greater than 5% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance with the PM standard.
[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070 and 62-212.400 (BACT) F.A.C]

C.9. Best Management Practices to Control Unconfined Emissions of PM. To ensure the emission standards with regard to opacity and PM of this subsection are complied with, the procedures set forth in **Specific Condition FW5** of **Section II** of this permit, "Unconfined Emissions of Particulate Matter," shall be adhered to where practical and cost effective. In addition, the procedures set forth in the BMP Plan contained in **Appendix BMP in Section VI** of this permit with regard to fugitive emissions shall be adhered to. [Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-4.070, 62-296.320 and 62-212.400 (BACT) F.A.C.]

Test Methods and Procedures

C.10. Annual Compliance Test.: During each federal fiscal year (October 1st to September 30th), the fly ash dust collectors associated with this emission unit shall be tested to demonstrate compliance with the VE emissions standards specified in **Specific Condition C.6.** of this subsection. During each federal fiscal year (October 1st to September 30th), the fly ash silo baghouse associated with this emission unit shall be tested to demonstrate compliance with the VE emissions standard specified in **Specific Condition C.8.** of this subsection. [Rules 62-297.310(7)(a)4, 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

C.11. Fly Ash Silo PM Compliance Test. The annual VE tests in **Specific Condition C.10.** of this subsection with regard to the fly ash silo baghouse shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Specific Condition C.8.** of this subsection is not met for the fly ash silo baghouse, a PM test utilizing EPA Method 5 must be conducted on the baghouse stack to show compliance with the PM emissions standard in **Specific Condition C.7.** of this subsection within 60 days of the VE test. [Rule 62-297.620(4), F.A.C.]

C.12. Test Methods. Any required tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
EPA 5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

[Permit No. 0010131-003-AC (PSD-FL-411B); Rules 62-204.800, F.A.C.; and 40 CFR 60, Appendix A]

Recordkeeping and Reporting Requirements

C.13. Test Reports. The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in **Appendix TR** (Common Testing Requirements) in **Section VI** of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

Subsection E. The specific conditions in this section apply to the following emissions unit:

EU ID No.	Brief Description
005	One emergency generator diesel engine

The emergency generator diesel engine has a maximum design engine output rating of 1,220 horsepower (hp); equivalent to an engine output rating of 910 kilowatts (kW).

NSPS and NESHAP Applicability

D.1. NSPS Subpart IIII Applicability The emergency generator diesel engine is a Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. The permittee shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the diesel engine and its operations (e.g. non-road, emergency, displacement, capacity and model year selected). Excerpts of the applicable requirements from Subpart IIII are contained in this subsection while the entire subpart is provided in **Appendix IIII in Section VI** of this permit. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

{Permitting Note: The requirements of Subpart IIII are provided *for clarity and convenience in this subsection. However, if all the applicable requirements from the subpart are not contained in this subsection, the permittee is still subject to the omitted requirements.}*

D.2. NESHAPS Subpart ZZZZ Applicability. The emergency generator diesel engine is a Liquid Fueled Reciprocating Internal Combustion Engine (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the emergency generator diesel engine must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements of Subpart ZZZZ apply to the emergency generator diesel engine. [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

Equipment

D.3. Emergency Generator Diesel Engine. The permittee is authorized to operate and maintain one emergency generator diesel engine with a maximum design engine output rating of 1,220 hp (910 kW). [Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

D.4. ULSD Fuel Oil Storage Tank: The permittee is authorized to operate and maintain a 5,750-gallon tank to store ULSD fuel oil for use in the emergency generator diesel engine. Permit No. 0010131-003-AC (PSD-FL-411B); and [Rule 62-4.070(3), F.A.C.]

{Permitting Note: The ULSD fuel oil storage tank for the emergency generator engine at the GREC facility is not subject to NSPS Subpart Kb because it stores a liquid (ULSD fuel oil) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly it is an unregulated emissions unit.} [40 CFR 60.110b(a) and (b) and Rule 62-204.800(8)(b)16, F.A.C.]

Essential Potential to Emit (PTE) Parameters

D.5. Hours of Operation. The emergency generator diesel engine may operate up to 100 hours per year for maintenance and testing purposes.

a. There is no time limit on the use of emergency stationary ICE in emergency situations.

b. You may operate your emergency stationary ICE for any combination of the purposes specified in "i" to "iii" below for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed in "c." below counts as part of the 100 hours per calendar year.

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

ii. Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

iii. Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

c. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph "b." above. Except as provided in paragraph "d." below, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

d. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

i. The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

ii. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

iii. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

iv. The power is provided only to the facility itself or to support the local transmission and distribution system.

v. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.; NSPS Subpart IIII, §60.4211(f)]

D.6. Authorized Fuel. The emergency generator diesel engine shall fire ULSD fuel oil. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight.
[Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

Emission Limitations and Standards

D.7. Emissions Limits. The emergency generator diesel engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Emergency Generator (> 560 kW and ≤ 2,237 kW)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**SO_2**[2] **(% S)**	**NMHC**[3]**+NO_X** (g/kW-hr)
Subpart IIII (2006 and later)	3.5	0.2	0.0015	6.4

1. g/kW-hr means grams per kilowatt-hour.
2. SO_2 emission standard will be met by using ULSD fuel oil in the emergency generator diesel engine with a fuel sulfur (S) content of 0.0015% by weight.
3. NMHC means Non-Methane Hydrocarbons

[Permit No. 0010131-003-AC (PSD-FL-411B), NSPS Subpart IIII; and Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

Test Methods and Procedures

D.8. Emergency Generator Testing Requirements. The unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and NO_X. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. As an alternative, an EPA certification of emissions characteristics of the purchased model that are at least as stringent as the BACT (NSPS Subpart IIII) values and the use of ULSD fuel oil with a sulfur content of 15 ppm or less can be used to fulfill this requirement. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and NSPS Subpart IIII, §60.4210 and §60.4211(e)(1) and (2)]

D.9. Test Methods. Any required tests shall be performed in accordance with the in-use testing procedures in 40 CFR 1039, Subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR 1042, Subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. [NSPS Subpart IIII, §60.4212(a)]

Recordkeeping and Reporting Requirements

D.10. Notification, Recordkeeping and Reporting Requirements. The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [40 CFR 60.4211]

D.11. Notifications Reporting and Recordkeeping. . Notifications reporting and recordkeeping are required pursuant to 40 CFR 60.7, and NSPS Subpart IIII, §60.4214(b) and §60.4214(d) for the 910-kW emergency generator diesel engine. [NSPS Subpart IIII, §60.4214(b) and (d)]

D.12. 40 CFR 60 General Provisions. Table 8 from Subpart IIII shows which parts of the General Provisions in §§60.1 through 60.19 apply to the emergency generator diesel engine. [§60.4218]

Subsection E. The specific conditions in this section apply to the following emissions unit:

EU ID No.	Brief Description
006	One emergency firewater pump diesel engine

The emergency firewater pump diesel engine has a maximum design output rating of 315 hp equivalent to an engine output rating of 235 kW.

NSPS and NESHAP Applicability

E.1. NSPS Subpart IIII Applicability. The fire pump engine is a Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. The applicant shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emission unit and its operations (e.g. non-road, emergency, displacement, capacity and model year selected). The applicable requirements on a top level basis from Subpart IIII are contained in this subsection while the entire subpart is provided in **Appendix IIII in Section VI** of this permit. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

{Permitting Note: The requirements of Subpart IIII are provided *for clarity and convenience in this subsection. However, if all the applicable requirements from the subpart are not contained in this subsection, the permittee is still subject to the omitted requirements.}*

E.2. NESHAPS Subpart ZZZZ Applicability. The fire pump engine is a Liquid Fueled Reciprocating Internal Combustion Engine (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the fire pumps must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements of Subpart ZZZZ apply to the emergency fire pumps. [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

Equipment

E.3. Engine Driven Pump. The permittee is authorized to operate and maintain one emergency diesel fire pump engine. The pump engine will have a maximum design output rating of 315 hp.
[Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

E.4. ULSD Fuel Oil Storage Tank. The permittee is authorized to operate and maintain a 1,000 gallon tank to store ULSD fuel oil for use in the emergency diesel firewater pump engine. [Rule 62-4.070(3), F.A.C.]

{Permitting Note: The ULSD fuel oil storage tank for the emergency diesel firewater pump engine at the GREC facility is not subject to NSPS Subpart Kb because it stores a liquid (ULSD fuel oil) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly it is an unregulated emissions unit.}
[40 CFR 60.110b(a) and (c) and Rule 62-204.800(7)(b), F.A.C.]

Essential Potential to Emit (PTE) Parameters

E.5. Hours of Operation. The emergency fire pump may operate up to 100 hours per year for maintenance and testing purposes.

a. There is no time limit on the use of emergency stationary ICE in emergency situations.

b. You may operate your emergency stationary ICE for any combination of the purposes specified in "i" to "iii" below for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed "c." below counts as part of the 100 hours per calendar year.

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

ii. Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

iii. Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

c. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph "b." above. Except as provided in paragraph "d." below, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

d. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

i. The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

ii. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

iii. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

iv. The power is provided only to the facility itself or to support the local transmission and distribution system.

v. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.; NSPS Subpart IIII, §60.4211(f)]

E.6. Authorized Fuel. The emergency fire pump shall fire ULSD fuel oil. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight. [Permit No. 0010131-003-AC (PSD-FL-411B) and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

Emission Limitations and Standards

E.7. Emissions Limits. The emergency firewater pump diesel engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Emergency Firewater Pump Engine (300 hp > and ≤600 hp)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**SO_2**[2] **(% S)**	**NMHC**[3]**+NO_X** (g/kW-hr)
Subpart IIII (2009 and later)	2.6	0.15	0.0015	3.0

1. g/kW-hr means grams per kilowatt-hour.
2. SO_2 emission standard will be met by using ULSD fuel oil in the emergency firewater pump engine with fuel sulfur (S) content of 0.0015% by weight.
3. NMHC means Non-Methane Hydrocarbons

[Permit No. 0010131-003-AC (PSD-FL-411B), NSPS Subpart IIII; and Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

Test Methods and Procedures

E.8. Emergency Fire Pump Testing Requirements. The unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and NO_X. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. As an alternative, an EPA certification of emissions characteristics of the purchased model that are at least as stringent as the BACT (NSPS Subpart IIII) values and the use of ULSD fuel oil with a sulfur content of 15 ppm or less can be used to fulfill this requirement. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and NSPS Subpart IIII, §60.4210 and §60.4211]

E.9. Test Methods. Any required tests shall be performed in accordance with the in-use testing procedures in 40 CFR 1039, Subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR 1042, Subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

[NSPS Subpart IIII, §60.4212]

Recordkeeping and Reporting Requirements

E.10. Notification, Recordkeeping and Reporting Requirements. The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [40 CFR 60.4211]

E.11. Notifications Reporting and Recordkeeping. Notifications reporting and recordkeeping are required pursuant to 40 CFR 60.7, 40 CFR 63.9, and NSPS Subpart IIII, §60.4214(b) and §60.4214(d) for the emergency firewater pump engine.

E.12. 40 CFR 60 General Provisions. Table 8 from Subpart IIII shows which parts of the General Provisions in §§60.1 through 60.19 the emergency firewater pump engine. [§60.4218]

Subsection F. The specific conditions in this section apply to the following emissions unit:

EU ID No.	Brief Description
007	Alkaline sorbent storage silo

Equipment

F.1. Alkaline Sorbent Storage Silo. The permittee is authorized to operate an alkaline sorbent storage silo to store hydrated lime or trona (or equivalent) for use by the IDSIS. A bin vent filter is installed on the sorbent storage silo to control PM emissions while the silo is loaded with sorbent from trucks. The bin vent filter is designed to achieve a PM emission rate of 0.01 gr/dscf. [Permit No. 0010131-003-AC (PSD-FL-411B)]

Essential Potential to Emit (PTE) Parameters

F.2. Hours of Operation. The hours of operation of this emission unit are not restricted (8,760 hours/year). [Permit No. 0010131-003-AC (PSD-FL-411B)]

Emission Limitations and Standards

F.3. Alkaline Sorbent Storage Silo VE. Opacity from the bin vent filter of the alkaline sorbent storage silo shall not exceed 5% opacity based on EPA Method 9 during annual tests.
[Permit No. 0010131-003-AC (PSD-FL-411B); and Rules 62-212.400 (BACT) F.A.C. and 62-4.070, F.A.C]

F.4. PM Emission Standard. PM emissions from the bin vent filter of the alkaline sorbent storage silo shall not exceed 0.01 gr/dscf. [Permit No. 0010131-003-AC (PSD-FL-411B); and Rules 62-212.400 (BACT) F.A.C. and 62-4.070, F.A.C]

F.5. Alkaline Sorbent Storage Silo Bin Vent Filter PM Standard by Opacity Measurement. A VE reading of 5% opacity or less may be used to demonstrate compliance with the PM emission standard in **Specific Condition F.4** above. A VE reading greater than 5% opacity will require the permittee to perform a PM emissions test on the alkaline sorbent storage silo bin vent filter within 60 days to show compliance with the PM standard given in **Specific Condition F.4** above. [Permit No. 0010131-003-AC (PSD-FL-411B); and Rules 62-296.712, 62-212.400 (BACT) F.A.C. and 62-4.070, F.A.C.]

Test Methods and Procedures

F.6. Annual Stack Tests. If required, the sorbent storage silo shall be tested annually to demonstrate compliance with the emission standards for PM in accordance with test methods specified in this permit. [Rules 62-212.400 (BACT) F.A.C. and 62-4.070, F.A.C.]

F.7. Test Methods. Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
5, 5B, 17	Measurement of PM
9	Visual Determination of the Opacity
201, 201A	Measurement of PM_{10}

[Rules 62-212.400 (BACT) F.A.C. and 62-4.070, F.A.C]

Recordkeeping and Reporting Requirement

F.8. Test Reports. The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in **Appendix TR** (Common Testing Requirements) in **Section VI** of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

Operated by: Gainesville Renewable Energy Center, LLC
ORIS Code: 57241

The emissions units listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
-002	Woody biomass-fueled BFB boiler with a maximum heat input capacity of 1,358 million British thermal units per hour (MMBtu/hr)

A.1. The Phase II Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:

a. DEP Form No. 62-210.900(1)(a), dated 01/31/14, received 02/11/14.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.3. Sulfur Dioxide (SO_2) Emission Allowances. SO_2 emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

A.4. Comments, Notes, and Justifications: None.

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☐ New ■ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Gainesville Renewable Energy Center Plant name	Florida State	57241 ORIS/Plant Code

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-In Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-In Units Monitor Certification Deadline
BFB1	**No**	**Yes**	**August 16, 2013**	**February 12, 2014**

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

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Gainesville Renewable Energy Center
Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(I) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(II) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(I) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
(II) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit 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.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(I) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; 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 Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(I) Starting January 1, 2000, an Acid Rain 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 Acid Rain unit under 40 CFR 72.6(a)(3).
(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 Part application, the Acid Rain Part, 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 Acid Rain 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 Acid Rain unit 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 Acid Rain unit 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 Acid Rain 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 EPA or the DEP:
(I) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; 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 of a new certificate of representation changing the designated representative;
(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,

Gainesville Renewable Energy Center
Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain Part 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 Acid Rain source and each Acid Rain 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 Part application, an Acid Rain Part, 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 Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain 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 Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 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 Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit 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
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/06

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Gainesville Renewable Energy Center, LLC
Plant Name (from STEP 1)

STEP 5

For SO_2 Opt-in units only. (Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature	Date

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain 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.

Leonard J. Fagan Name	Vice President of Engineering Title
Gainesville Renewable Energy Center, LLC Owner Company Name	
(617) 904-3100 ext. 122 Phone	lenfagan@emienergy.com E-mail address
Signature	Date 1/31/2014

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

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Clean Air Interstate Rule (CAIR).

Operated by: Gainesville Renewable Energy Center, LLC
Plant: Gainesville Renewable Energy Center
ORIS Code: 57241

The emissions unit below is regulated under the Clean Air Interstate Rule.

EU No.	EPA Unit ID#	Brief Description
002	BFB1	Woody biomass-fueled BFB boiler with a maximum heat input capacity of 1,358 million British thermal units per hour (MMBtu/hr)

1. Clean Air Interstate Rule Application. The Clean Air Interstate Rule Part Form submitted for this facility is a part of this permit. The owners and operators of these CAIR units as identified in this form must comply with the standard requirements and special provisions set forth in the CAIR Part Form (DEP Form No. 62-210.900(1)(b)) dated April 8, 2014, which is attached at the end of this section. [Chapter 62-213, F.A.C. and Rule 62-210.200, F.A.C.]

Clean Air Interstate Rule (CAIR) Part

For more information, see instructions and refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321 and 96.322; and Rule 62-296.470, F.A.C.

This submission is: ☐ New ■ Revised ☐ Renewal

STEP 1

Identify the source by plant name and ORIS or EIA plant code

Gainesville Renewable Energy Center Plant Name:	**Florida** State:	**57241** ORIS or EIA Plant Code:

STEP 2

In column "a" enter the unit ID# for every CAIR unit at the CAIR source.

In columns "b," "c," and "d," indicate to which CAIR program(s) each unit is subject by placing an "X" in the column(s).

For new units, enter the requested information in columns "e" and "f.

a	b	c	d	e	f
Unit ID#	Unit will hold nitrogen oxides (NO_X) allowances in accordance with 40 CFR 96.106(c)(1)	Unit will hold sulfur dioxide (SO_2) allowances in accordance with 40 CFR 96.206(c)(1)	Unit will hold NO_X Ozone Season allowances in accordance with 40 CFR 96.306(c)(1)	New Units Expected Commence Commercial Operation Date	New Units Expected Monitor Certification Deadline
BFB1	**X**	**X**	**X**	**August 16, 2013**	**February 12, 2014**

DEP Form No. 62-210.900(1)(b) – Form
Effective: 3/16/08

1

	Gainesville Renewable Energy Center
STEP 3	
	Plant Name (from STEP 1)

Read the standard requirements.

CAIR NOx ANNUAL TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NOx source and each CAIR NOx unit at the source shall:
(I) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.122 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(II) [Reserved];
(2) The owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CC, and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NOx source and each CAIR NOx unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH, shall be used to determine compliance by each CAIR NOx source with the following CAIR NOx Emissions Requirements.

NO_X Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NOx allowances available for compliance deductions for the control period under 40 CFR 96.154(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 40 CFR Part 96, Subpart HH.
(2) A CAIR NOx unit shall be subject to the requirements under paragraph (1) of the NOx Requirements starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.170(b)(1) or (2) and for each control period thereafter.
(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Requirements, for a control period in a calendar year before the year for which the CAIR NOx allowance was allocated.
(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FF and GG.
(5) A CAIR NOx allowance is a limited authorization to emit one ton of NOx in accordance with the CAIR NOx Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR Part, or an exemption under 40 CFR 96.105 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NOx allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EE, FF, or GG, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NOx unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X unit.

Excess Emissions Requirements.

If a CAIR NOx source emits NOx during any control period in excess of the CAIR NOx emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under 40 CFR 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source and each CAIR NO_X 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 before the end of 5 years, in writing by the DEP or the Administrator.
(I) The certificate of representation under 40 CFR 96.113 for the CAIR designated representative for the source and each CAIR NO_X unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(II) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HH, 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 CAIR NO_X Annual Trading Program.
(IV) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_X Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program.
(2) The CAIR designated representative of a CAIR NOx source and each CAIR NOx unit at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, including those under 40 CFR Part 96, Subpart HH.

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Liability.

(1) Each CAIR NO_X source and each CAIR NO_X unit shall meet the requirements of the CAIR NO_X Annual Trading Program.
(2) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X source or the CAIR designated representative of a CAIR NO_X source shall also apply to the owners and operators of such source and of the CAIR NO_X units at the source.
(3) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X unit or the CAIR designated representative of a CAIR NO_X unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_X Annual Trading Program, a CAIR Part, or an exemption under 40 CFR 96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source or CAIR NO_X unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR SO_2 TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall:
(I) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.222 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(II) [Reserved];
(2) The owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CCC, for the source and operate the source and each CAIR unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR SO_2 source and each SO_2 CAIR unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96 ,Subpart HHH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH, shall be used to determine compliance by each CAIR SO_2 source with the following CAIR SO_2 Emission Requirements.

SO_2 Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO_2 allowances available for compliance deductions for the control period, as determined in accordance with 40 CFR 96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHH.
(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (1) of the Sulfur Dioxide Emission Requirements starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.270(b)(1) or (2) and for each control period thereafter.
(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the SO_2 Emission Requirements, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.
(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFF and GGG.
(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR Part, or an exemption under 40 CFR 96.205 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR SO_2 allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or GGG, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR SO_2 unit.

Excess Emissions Requirements.

If a CAIR SO_2 source emits SO_2 during any control period in excess of the CAIR SO_2 emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under 40 CFR 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable state law.

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Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 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 before the end of 5 years, in writing by the Department or the Administrator.
(I) The certificate of representation under 40 CFR 96.213 for the CAIR designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 of a new certificate of representation under 40 CFR 96.213 changing the CAIR designated representative.
(II) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHH, 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 CAIR SO_2 Trading Program.
(IV) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO_2 Trading Program.
(2) The CAIR designated representative of a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR SO_2 Trading Program, including those under 40 CFR Part 96, Subpart HHH.

Liability.

(1) Each CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program.
(2) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 source or the CAIR designated representative of a CAIR SO_2 source shall also apply to the owners and operators of such source and of the CAIR SO_2 units at the source.
(3) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 unit or the CAIR designated representative of a CAIR SO_2 unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR SO_2 Trading Program, a CAIR Part, or an exemption under 40 CFR 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR NO_x OZONE SEASON TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall:
(I) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.322 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(II) [Reserved];
(2) The owners and operators of each CAIR NO_x Ozone Season source required to have a Title V operating permit or air construction permit, and each CAIR NO_x Ozone Season unit required to have a Title V operating permit or air construction permit at the source shall have a CAIR Part included in the Title V operating permit or air construction permit issued by the DEP under 40 CFR Part 96, Subpart CCCC, for the source and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HHHH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHHH, shall be used to determine compliance by each CAIR NO_x Ozone Season source with the following CAIR NO_x Ozone Season Emissions Requirements.

NO_x Ozone Season Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_x Ozone Season allowances available for compliance deductions for the control period under 40 CFR 96.354(a) in an amount not less than the tons of total NO_x emissions for the control period from all CAIR NO_x Ozone Season units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHHH.
(2) A CAIR NO_x Ozone Season unit shall be subject to the requirements under paragraph (1) of the NO, Ozone Season Emission Requirements starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.370(b)(1),(2), or (3) and for each control period thereafter.
(3) A CAIR NO_x Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_x Ozone Season Emission Requirements, for a control period in a calendar year before the year for which the CAIR NO_x Ozone Season allowance was allocated.
(4) CAIR NO_x Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_x Ozone Season Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFFF and GGGG.
(5) A CAIR NO_x Ozone Season allowance is a limited authorization to emit one ton of NO_x in accordance with the CAIR NO_x Ozone Season Trading Program. No provision of the CAIR NO_x Ozone Season Trading Program, the CAIR Part, or an exemption under 40 CFR 96.305 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NO_x Ozone Season allowance does not constitute a property right.

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(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EEEE, FFFF or GGGG, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X Ozone Season unit.

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Excess Emissions Requirements.

If a CAIR NO_X Ozone Season source emits NO_X during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under 40 CFR 96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAAA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season 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 before the end of 5 years, in writing by the DEP or the Administrator.
(I) The certificate of representation under 40 CFR 96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(II) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHHH, 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 CAIR NO_X Ozone Season Trading Program.
(IV) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under 40 CFR Part 96, Subpart HHHH.

Liability.

(1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.
(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR Part, or an exemption under 40 CFR 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

STEP 4

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the CAIR source or CAIR 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.

Leonard J. Fagan Name	**Vice President of Engineering** Title
Gainesville Renewable Energy Center, LLC Company Owner Name	
(617) 904-3100 ext. 122 Phone	**lenfagan@emienergy.com** E-mail Address
	April 8, 2014 Date

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SECTION VI. APPENDICES.

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A, Glossary
Appendix AS, Requirements (Excerpts) of GREC Settlement Agreement Related to Air Issues
Appendix BMP, Best Management Practices Plan.
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix CEMS.
Appendix F, 40 CFR 75, Appendix F, Section 5 – Measurement of Boiler Heat Input Rate.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix NESHAP, Subpart A – General Provisions.
Appendix NESHAP Subpart DDDDD - Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
Appendix NESHAP, Subpart ZZZZZ - Stationary Reciprocating Internal Combustion Engines
Appendix NSPS, Subpart A – General Provisions.
Appendix NSPS, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units
Appendix NSPS, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Appendix RR, Facility-wide Reporting Requirements.
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.
Appendix U, List of Unregulated Emissions Units and/or Activities