Florida Power and Light Company
Manatee Power Plant

Facility ID No. 0810010

Manatee County

Title V Air Operation Permit Renewal

Permit No. 0810010-025-AV
(Renewal of Title V Air Operation Permit No. 0810010-019-AV)

Permitting Authority

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
Permitting Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000
Email: DARM_Permitting@dep.state.fl.us

Compliance Authority

State of Florida
Department of Environmental Protection
Southwest District Office

13051 North Telecom Parkway
Temple Terrace, Florida 33637-0926

Telephone: (813) 632-7600
Email: SWD_Air@dep.state.fl.us

Title V Air Operation Permit Renewal
Permit No. 0810010-025-AV

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Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Carlos Lopez-Cantera
Lt. Governor

Noah Valenstein
Secretary

PERMITTEE:
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Permit No. 0810010-025-AV
Manatee Power Plant
Facility ID No. 0810010
Title V Air Operation Permit Renewal

The purpose of this permit is to renew Title V air operation permit No. 0810010-019-AV for the above referenced facility and to incorporate the provisions of final air construction permit No. 0810010-024-AC (PSD-FL-328E), which authorized the installation of the new GE FA.05 turbine components to improve the efficiency of Unit 3, and the minor revisions authorized by permit No. 0810010-026-AC/PSD-FL-328F, which is being issued concurrently with this renewal. The existing Manatee Power Plant is located in Manatee County at 19050 State Road 62, Parrish, Florida. The Universal Transverse Mercator (UTM) coordinates are: Zone 17, 367.15 km East and 3054.23 km North. Latitude is: 27° 36' 20.0133" North; and, Longitude is: 82° 20' 46.5245" West.

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 shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

0810010-025-AV Effective Date: June 4, 2018
Renewal Application Due Date: October 21, 2022
Expiration Date: June 3, 2023

Executed in Tallahassee, Florida.

Jonathan Holtom

Digitally signed by Jonathan Holtom, P.E.
Date: 2018.06.04 08:11:46 -04'00'

for:

Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

SA/jh

Subsection A. Facility Description.

This nominal 2,899.6-megawatt (MW) facility consists of two fossil fuel steam generators, a "4-on-1" gas-fired combined cycle unit and associated support equipment.

Fossil Fuel Steam Generators, Unit 1 and Unit 2: Each unit is a Foster-Wheeler Steam Generator rated at 800 MW (900 MW gross capacity) output. These units burn a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from Florida Power and Light Company (FPL) operations, discharging pollutants through a stack 499 feet above ground level. Each unit is equipped with a flue gas recirculation system and staged combustion and also operates a Westinghouse tandem compound, reheat-type extraction turbine. The project authorized by air construction permit No. 0810010-016-AC was to construct two electrostatic precipitators (ESP) on Units 1 and 2. The existing cyclones used to control PM/PM_{10} emissions from the units were removed and replaced by the ESP equipment. In addition, to handle the additional fly ash collected by the ESP, a fly ash handling, storage and shipment system including two storage silos was installed.

Combined Cycle Gas Turbine, Unit 3 (EU No's 005 - 008): These units consist of four ("4-on-1") nominal 207.4 MW General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems, an automated gas turbine control system, an inlet air filtration system, four 495 million British thermal units per hour (MMBtu/hr) supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors, a single nominal 470 MW steam-electrical generator that serves all four gas turbine/HRSG systems, four 120 feet exhaust stacks, and associated support equipment. The total generating capacity of the "4-on-1" combined cycle system Unit 3 is 1,299.6 MW.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities (See Appendix I and Appendix U).

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
	Regulated Emissions Units
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
003	Emergency Diesel RICE Generator for Unit 1 and Unit 2; 1,000 kW; 32.10 L; 12-cylinder
005	Unit No. 3A Gas Turbine (nominal 184 MW) with Heat Recovery Steam Generator
006	Unit No. 3B Gas Turbine (nominal 184 MW) with Heat Recovery Steam Generator
007	Unit No. 3C Gas Turbine (nominal 184 MW) with Heat Recovery Steam Generator
008	Unit No. 3D Gas Turbine (nominal 184 MW) with Heat Recovery Steam Generator
012	Fly Ash Handling, Storage and Shipment System
014	Fire Pump Engine for Facility
	Unregulated Emissions Units and Activities
004	Painting of Plant Equipment and Non-Halogenated Solvent Cleaning Operations
010	Ammonia Storage Tank
011	Emergency Diesel Engines (2) 3,210 HP Each; Manufactured in 2005; Caterpillar
013	Two (2) Small Hurricane Hardening Program Propane "Emergency" Generators; 29.24 KW (40 HP)

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Subsection C. Applicable Regulations.

Based on the Title V air operation permit application received January 16, 2015, this facility is a major source of hazardous air pollutants (HAP). This facility is classified as a prevention of significant deterioration (PSD) major facility. A summary of applicable regulations is shown in the following table.

Regulation	EU No(s).
Federal Rule Citations	
40 CFR 60, Subpart A - NSPS General Provisions	003, 005, 006, 007, 008
40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines	005, 006, 007, 008
40 CFR 60, Subpart IIII - NSPS for Stationary Compression Ignition RICE	003
40 CFR 63, Subpart A - NESHAP General Provisions	001, 002, 014
40 CFR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units (these units may be subject to this rule if they meet the definition of oil fired EGUs)	001, 002
40 CFR 63, Subpart ZZZZ - NESHAP for Stationary RICE	014
40 CFR 75 Acid Rain Monitoring Provisions	001, 002, 005, 006, 007, 008
State Rule Citations	
Chapter 62-4, Florida Administrative Code (F.A.C.) (Permitting Requirements)	001, 002, 003, 005, 006, 007, 008, 012, 014
Chapter 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference)	
Chapter 62-210, F.A.C. (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms)	
Chapter 62-212, F.A.C. (Preconstruction Review, PSD Review and Best Available Control Technology (BACT))	
Chapter 62-213, F.A.C. (Title V Air Operation Permits for Major Sources of Air Pollution)	
Chapter 62-296, F.A.C. (Emission Limiting Standards)	
Chapter 62-297, F.A.C. (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures)	
Chapter 62-214, F.A.C. (Requirements for Sources Subject to The Federal Acid Rain Program)	001, 002, 005, 006, 007, 008
Rule 62-296.470, F.A.C. (Clean Air Interstate Rule) (CAIR)	001, 002, 005, 006, 007, 008

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

FW1. Appendices. The permittee shall comply with all documents identified in Section IV, 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. 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. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

FW5. Unconfined Particulate Matter. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. Paving and maintenance of roads, parking areas, and yards.
b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
c. Application of asphalt, water, oil, chemicals, or other dust suppressants to unpaved roads, yards, open stock piles, and similar activities.
d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment and from buildings or work areas to prevent particulate from becoming airborne.
e. Landscaping or planting of vegetation.
f. Use of hoods, fans, filter, and similar equipment to contain, capture, and/or vent particulate matter.
g. Confining abrasive blasting where possible.
h. Enclosure or covering of conveyor systems.

[Rule 62-296.320(4)(c)2., F.A.C.; and, provided by the applicant in Title V air operation permit renewal application received February 22, 2018.]

Reports and Fees

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

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 1st 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 and to the US. EPA at the address shown below within 60 days after the end of each calendar year during which the Title V air operation permit was effective. (See also Appendix RR, Conditions RR1 and RR7.) [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

U.S. Environmental Protection Agency, Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303
Attn: Air Enforcement Branch

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://www2.epa.gov/rmp. 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]

FW9. Semi-Annual Reports. The permittee shall monitor compliance with the terms and conditions of this permit and shall submit reports at least every six months to the compliance office. Each semi-annual report shall cover the 6-month periods of January 1 – June 30 and July 1 – December 31. The reports shall be submitted by the 60th day following the end of each calendar half (i.e., March 1st and August 29th of every year). All instances of deviations from permit requirements (including conditions in the referenced Appendices) must be clearly identified in such reports, including reference to the specific requirement and the duration of such deviation. If there are no deviations during the reporting period, the report shall so indicate. Any semi-annual reporting requirements contained in applicable federal NSPS or NESHAP requirements may

be submitted as part of this report. The submittal dates specified above shall replace the submittal dates specified in the federal rules. All additional reports submitted as part of this report should be clearly identified according to the specific federal requirement. All reports shall include a certification by a responsible official, pursuant to subsection 62-213.420(4), F.A.C. (See also Conditions RR2. – RR4. of Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements related to deviations.) [Rule 62-213.440(1)(b)3.a., F.A.C.; and, 40 CFR 60.19, 40 CFR 61.10 & 40 CFR 63.10]

{Permitting Note: EPA has clarified that, pursuant to 40 CFR 70.6(a)(3), the word "monitoring" is used in a broad sense and means monitoring (i.e., paying attention to) the compliance of the source with all emissions limitations, standards, and work practices specified in the permit.}

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Subsection A. Emissions Units 001 and 002

The specific conditions in this section apply to the following emissions unit(s):

EU No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Fossil fuel fired steam generators Unit 1 and Unit 2 are each nominal 800-megawatt (900 MW gross capacity) (electric) steam generators designated as Manatee Power Plant Unit 1 and Unit 2. The emissions units are fired on a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations. Propane is utilized primarily for ignition of the main fuel. When firing fuel oil (or combinations of authorized fuels), the maximum heat input for each boiler is 8,650 MMBtu per hour. When firing natural gas alone, the maximum heat input for each boiler shall not exceed 8,650 MMBtu per hour.

Each emissions unit consists of a boiler which produces steam to drive a turbine generator. Emissions are controlled with a flue gas recirculation system, reburn and staged combustion. The twin register low nitrogen oxides (NO_X) burners (ABB Combustion Services, Ltd.) are dual fuel with mechanical atomization for oil firing. Each unit is equipped with a 499 foot stack height. The stack for Unit 1 has a 27.3 foot exit diameter; the stack for Unit 2 has a 26.2 foot exit diameter. Flow rate is 2,739,143 actual cubic feet per minute (acfm), exit velocity is 78 feet per second (fps), exit temperature is 344º F for Unit 1; flow rate is 2,667,410 acfm, exit velocity is 82.5 fps, exit temperature is 325º F for Unit 2.

Emissions of particulate matter (PM/PM_{10}) from Units 1 and 2 are controlled by electrostatic precipitators (ESP). To manage the fly ash collected by the ESP devices, a fly ash handling, storage and shipment system including two storage silos is operated. Based on initial compliance testing performed following the installation of this ESP control equipment, these units are able to meet the PM and VE emissions limits without operating the ESP while firing natural gas alone, as well as while co-firing oil up to approximately a 70% blend. When the ESP control equipment is required to be operated in order to meet the emissions limits at higher percentages of oil combustion, these units are subject to the compliance assurance monitoring (CAM) provisions contained in the attached Appendix CAM. These units are predominantly fired only on natural gas.

{Permitting Notes: These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. These units will also be subject to 40 FR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units at such time that a unit fires oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. See Specific Condition ***A.33.****, below. Fossil fuel fired steam generator Unit 1 began commercial operation in 1976 and fossil fuel fired steam generator Unit 2 began commercial operation in 1977. These emissions units may inject additives such as magnesium oxide, magnesium hydroxide and related compounds into each boiler.}*

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. When firing fuel oil or natural gas alone, the maximum heat input rate to each unit shall not exceed 8,650 MMBtu per hour. When a blend of fuel oil and natural gas is fired, the maximum heat input to each unit shall not exceed 8,650 MMBtu per hour. [0810010-017-AC, Specific Condition A.2.]

{Permitting Note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.2. Emissions Unit Operating Rate Limitation During and After Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case,

subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. (See also the related testing provisions in Appendix TR, Facility-wide Testing Requirements.) [Rule 62-297.310(3), F.A.C.]

A.3. Authorized Fuel. Authorized fuels to be burned are low sulfur fuel oil containing a maximum of 0.7% sulfur content, by weight; natural gas; or, a mixture of low sulfur fuel oil containing a maximum of 1.0% sulfur content, by weight, and natural gas in a ratio that shall not exceed the sulfur dioxide emission limitation standard of 0.80 lb/MMBtu heat input. [0810010-017-AC, Specific Condition A.3.]

A.4. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

A.5. Circumvention. When a unit is firing oil, the permittee shall not circumvent the ESP or allow the emission of air pollutants without this equipment operating properly per the manufacturers operating instructions. [Rule 62-210.650, F.A.C.; and, 0810010-016-AC, Specific Condition A.3.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **A.6. - A.11.** are based on the specified averaging time of the applicable test method.

A.6. Normal Opacity Limit. During normal operation, visible emissions (VE) shall be not exceed 20 percent (%) opacity as determined by a continuous opacity monitoring system (COMS) or EPA Method 9. [0810010-016-AC, Specific Condition A.4.]

A.7. Opacity Limit During Soot Blowing and Load Change. VE shall not exceed 40% opacity as determined by COMS or EPA Method 9 during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

a. A load change occurs when the operational capacity of a unit is in the 10% to 100% capacity range, other than startup or shutdown, which exceeds 10% of the unit's rated capacity and which occurs at a rate of 0.5% per minute or more.
b. VE above 40% opacity shall be allowed for not more than four, 6-minute periods, during the 3-hour period of excess emissions allowed by this condition.

[0810010-016-AC, Specific Condition A.5.]

A.8. Normal PM/PM_{10} Emissions Limit. During normal operation, PM/PM_{10} emissions shall not exceed 0.03 pounds per MMBtu of heat input (lb/MMBtu). [0810010-016-AC, Specific Condition A.6.]

A.9. PM/PM_{10} Emissions Limit During Soot Blowing and Load Change. PM/PM_{10} emissions shall not exceed 0.10 lb/MMBtu during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [0810010-016-AC, Specific Condition A.7.]

A.10. Sulfur Dioxide (SO_2). Sulfur dioxide emissions rate from each fossil fuel fired steam electric generator Units 1 and 2 shall not exceed 0.80 lb/MMBtu during any rolling 12 months. [0810010-017-AC, Specific Condition A.4.]

A.11. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.25 pounds per million Btu heat input. Compliance shall be demonstrated based on a 30-day rolling average as measured by a continuous emission monitoring system (CEMS). The CEMS must meet the performance specifications contained in 40 CFR 75. [Rule 62-296.405(1), F.A.C.; AO41-204804, AO41-219341, issued August 30, 1993 & 0810010-010-AC, Specific Condition 6.; and, Agreement with the Department dated September 19, 2002]

Excess Emissions

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

A.12. Malfunction. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

A.13. Startup or Shutdown. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

A.14. Prohibition. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(1) & (2), F.A.C.]

Monitoring of Operations

A.15. CAM Plan. When the ESP control equipment is required to be operated in order to meet the PM emissions limits at higher percentages of oil combustion, these emissions units are 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. [Rules 62-204.800 & 62-213.440(1)(b)1.a., F.A.C.; and, 40 CFR 64]

Continuous Monitoring Requirements

A.16. COMS for Periodic Monitoring. The owner or operator was required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring. [Rule 62-213.440, F.A.C.; and, applicant agreement with EPA on March 3, 1998.]

{Permitting Note: In addition, Units 1 and 2 are no longer required to operate continuous opacity monitors (COMs) so long as each Unit maintains "gas-firing" status according to Part 75. Part 75 exempts "gas-fired" units from opacity monitor requirements by way of the definition in 40 CFR 72.2. The Manatee Units 1 & 2 meet the gas-fired definition. Also, Rule 62-296.405 (1)(f)1, F.A.C., requires that fossil fueled steam generators with capacity factors greater than 30% must install opacity monitors. Manatee Units 1 & 2 are well below the 30 % capacity factor requirement. Therefore, opacity monitors are no longer required. In the future if FP&L Manatee, Unit 1 or 2 fails to meet the definition of gas-fired in 40 CFR 72, then FP&L has one year to install and certify an opacity monitor from the end of year in which the units at Manatee do not meet the definition of a gas-fired unit in 40 CFR 72.2 and specific Conditions A.5. (COMs portion). A.6. (COMs portion), and A.15. of this Permit shall once again apply.}

Test Methods and Procedures

A.17. Test Methods. Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5, 5B, or 5F	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM_{10}.)
6, 6A, 6B, or 6C	Determination of Sulfur Dioxide Emissions from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

Method	Description of Method and Comments
17	Determination of Particulate Matter Emissions from Stationary Sources
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The above methods are 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 62-296.405, F.A.C.]

A.18. Annual and Renewal Compliance Tests. Compliance tests shall be performed for these units according to the requirements in Specific Condition **A.19.** and at the following frequencies:

a. *Annual Tests Required Under Normal Operation*. During each calendar year (January 1st through December 31st) in which fuel oil is fired, either alone or in combination with other fuels for more than 400 hours, other than during startup, the stack associated with each EU shall be tested to demonstrate compliance with the emissions standards for VE given in Specific Condition **A.6.** and the emissions standards for PM/PM_{10} given in Specific Condition **A.8.**

b. *Annual Tests Required While Soot Blowing*. A compliance test shall also be conducted annually while the emissions unit is operating under soot blowing conditions in each calendar year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any calendar year in which fuel oil is not fired, either alone or in combination with other fuels, for more than 400 hours, other than during startup, to demonstrate compliance with the emissions standards for VE given in Specific Condition **A.7.** and the emissions standards for PM/PM_{10} given in Specific Condition **A.9.** [Rule 62-297.310(8)(a)2., F.A.C.]

c. *Renewal Tests*. Prior to obtaining a renewed operation permit, the stack associated with each EU shall be tested to demonstrate compliance with the emissions standards for VE given in Specific Conditions **A.6.** and **A.7.**, and the emissions standards for PM/PM10 given in Specific Conditions **A.8.** and **A.9.**

[Rules 62-297.310((8)(a)2.,3., 4. & 5, F.A.C.; and, 0810010-016-AC, Specific Condition A.10. & 0810010-018-AC, Specific Condition 5.]

A.19. Operating Conditions During Testing - PM and VE. When required, testing for particulate matter and visible emissions shall be conducted while firing No. 6 fuel oil at the maximum allowable rate of 8,650 million Btu per hour, except as provided below. Particulate matter and visible emissions shall be conducted under both soot-blowing and non-soot-blowing conditions and shall be conducted while injecting additives consistent with normal operating practices. Testing may be conducted while firing No. 6 fuel oil at less than 90 percent of the maximum allowable rate; however, subsequent emissions unit operation is limited as described in Appendix TR of this permit. [0810010-016-AC, Specific Condition A.11.]

A.20. Sulfur Dioxide. **The permittee elected to demonstrate compliance using fuel sampling and analysis.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. [Rule 62-296.405(1)(f)1.b., F.A.C.]

A.21. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-296.405(1)(f)1, F.A.C., and 40 CFR 75. [Rule 62-296.405, F.A.C.]

A.22. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

a. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

b. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
   (1) For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
   (2) For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

   In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[40 CFR 60, Appendix A]

A.23. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with a filter temperature of no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen-based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. [Rules 62-213.440 & 62-296.405(1)(e)2., F.A.C.; and, 40 CFR 60, Appendix A]

A.24. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedances of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance using fuel sampling and analysis.** [Rules 62-213.440 & 62-296.405(1)(e)3., F.A.C. and, 40 CFR 60, Appendix A]

A.25. Alternate Sampling Procedure. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard:

a. Compliance with the liquid fuel sulfur limit shall be verified by a fuel analysis provided by the vendor or performed by FPL upon each fuel delivery at the Port Manatee Fuel Oil Terminal with the following exception: in cases where No. 6 fuel oil is received with a sulfur content exceeding 0.7 percent by weight, and blending at the terminal is required to obtain a fuel mix equal to the applicable percent sulfur limit, an analysis of a fuel sample representative of fuel from the fuel storage tanks shall be performed by FPL prior to transferring oil to the Manatee plant. Reports of percent sulfur content of these analyses shall be maintained at the power plant facility. See Specific Condition A.3.

b. The owner or operator shall maintain records of the as-fired fuel oil heating value, density or specific gravity, and the percent sulfur content. Fuel sulfur content, percent by weight, for liquid fuels shall be determined by either ASTM D2622-94, ASTM D4294-90 (95), ASTM D1552-95, ASTM D1266-91, or both ASTM D4057-88 and ASTM D129-95 (or latest editions) to analyze a representative sample of the fuel oil.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. & 62-297.440, F.A.C.; Applicant Agreement with EPA on March 3, 1998; and, 0810010-017-AC, Specific Condition A.3.]

A.26. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices. [Rule 62-213.440, F.A.C.; and, Applicant agreement with EPA on March 3, 1998.]

A.27. 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(8), F.A.C.]

Recordkeeping and Reporting Requirements

A.28. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Fuel Analysis Report	Monthly	**A.30.**
Excess Emissions – VE & SO_2	Quarterly	**A.31.**
Excess Emissions - Malfunctions	Quarterly (if requested)	**A.32.**

[Rule 62-213.440(1)(b), F.A.C.]

A.29. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

A.30. Fuel Analysis Report. The owner or operator shall, by the fifteenth day following each calendar month, submit to the Department's Southwest District Office a report of fuel analyses that are representative of each fuel received in the preceding month. The report shall document the heating value, density or specific gravity, and the percent sulfur content by weight of each fuel fired. [Rule 62-213.440, F.A.C.; AO41-204804 Specific Condition 6 and AO41-219341, Specific Condition 6]

A.31. Excess Emissions - Reports. Submit to the Department's Southwest District Office a written report of emissions in excess of emission limiting standards for opacity and sulfur dioxide as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 & 62-296.405(1)(g), F.A.C.]

A.32. Excess Emissions - Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District Office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Southwest District Office. [Rule 62-210.700(6), F.A.C.]

Other Requirements

A.33. Used Oil. Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:

a. *On-specification Used Oil Allowed as Fuel*. This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a polychlorinated biphenyls (PCB) concentration of less than 50 parts per million (ppm), originating from FPL operations. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility. On-specification used oil shall meet the following specifications:
   (1) Arsenic shall not exceed 5.0 ppm;
   (2) Cadmium shall not exceed 2.0 ppm;
   (3) Chromium shall not exceed 10.0 ppm;
   (4) Lead shall not exceed 100.0 ppm;
   (5) Total halogens shall not exceed 1000 ppm;
   (6) Flash point shall not be less than 100 degrees F.
   [40 CFR 279, Subpart B.]

b. *Quantity Limited*. The maximum total quantity of used oil that may be burned in both emissions units is 40,000 gallons in any consecutive 12-month period.

c. *Used Oil Containing PCBs Not Allowed*. Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. *PCB Concentration of 2 to less than 50 ppm*. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. *Testing Required:* The owner or operator shall sample and analyze each batch of used oil to be burned for arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs. Additionally:
   (1) Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.
   (2) Split samples of the used oil shall be retained for three months after analysis for further testing if necessary.
   [AO41-204804 Specific Condition 9 and AO41-219341 Specific Condition 9]

f. *Record Keeping Required*. The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil received and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   (2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   (3) Results of the analyses required above.
   [40 CFR 279.61 and 761.20(e)]

g. *Reporting Required.* The owner or operator shall submit to the Department's Southwest District Office, within thirty days of the end of each calendar month in which used oil is burned, the analytical results and the total amount of on-specification used oil burned during the previous calendar month. The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

[Rule 62-213.440, F.A.C.; 40 CFR 279 and 40 CFR 761, unless otherwise noted]

40 CFR 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Requirements

A.34. Subpart UUUUU Requirements. In addition to the emissions limits shown above, if either unit meets the definition of an oil-fired electric utility steam generating unit in Subpart UUUUU, the permittee shall for that unit

also comply with the following emissions limits as applicable, and other Subpart UUUUU requirements based on a compliance date no later than April 16, 2015, with a 180-day period following that date to demonstrate compliance. The permittee must also meet all the applicable requirements of NESHAP 40 CFR 63, Subpart A – General Provisions, which is included in Appendix NESHAP, Subpart A - General Provisions.
Note: A unit meeting the definition for "natural gas-fired electric utility steam generating unit" is not subject to Subpart UUUUU [63.9983(b)]. "Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

a. Oil fired electric utility steam generating unit meeting the definition of limited-use liquid oil-fired subcategory are not subject to the emission standards, testing and reporting requirements for an Oil-fired electric utility steam generating unit. A "Limited-use liquid oil-fired subcategory" means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015. If either unit meets the definition of limited-use it is subject to the following requirements:
   (1) *Tune-Ups*. Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e). [63.9991]
   (2) *Continuous Compliance*. Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e). [63.10021]
   (3) *Reports*. Submit a Semi-Annual Compliance report according to 40 CFR 63.10031(b).

b. Oil fired electric utility steam generating units are subject to the following emission standards:
   (1) *Filterable Particulate Matter (PM)*. Emissions of PM shall not exceed either 0.030 pound/million British thermal unit (lb/MMBtu) or 0.30 pound per megawatt-hour (lb/MWh). In lieu of the filterable PM emission limit, the permittee may select to meet a total HAP metals emission limit of either 8.0×10^{-4} lb/MMBtu or either 8.0×10^{-3} lb/MWh. Finally, in lieu of ether filterable PM or total HAP metals emission limits the permittee my meet the following individual HAP metal emission limits:
      (a) Antimony (Sb) – 13 pounds per terra Btu (lb/TBtu) or 0.20 pounds per gigawatt hour (lb/GWh).
      (b) Arsenic (As) – 2.8 lb/TBtu or 3.0×10^{-2} lb/GWh.
      (c) Beryllium (Be) – 0.20 lb/TBtu or 2.0×10^{-3} lb/GWh.
      (d) Cadmium (Cd) – 0.30 lb/TBtu or 2.0×10^{-3} lb/GWh.
      (e) Chromium (Cr) – 5.5 lb/TBtu or 6.0×10^{-2} lb/GWh.
      (f) Cobalt (Co) – 21 lb/TBtu or 0.30 lb/GWh.
      (g) Lead (Pb) – 8.1 lb/TBtu or 8.0×10^{-2} lb/GWh.
      (h) Manganese (Mn) – 22 lb/TBtu or 0.30 lb/GWh.
      (i) Nickel (Ni) – 111 lb/TBtu or 1.1 lb/GWh.
      (j) Selenium (Se) – 3.3 lb/TBtu or 4.0×10^{-2} lb/GWh.
      (k) Mercury (Hg) – 0.20 lb/TBtu or 2.0×10^{-3} lb/GWh.
   (2) *Hydrogen Chloride (HCl)*. Emissions of HCl shall not exceed either 2.0×10^{-3} lb/MMBtu or 1.0×10^{-2} lb/MWh. As an alternative to monitoring and testing, the owner/operator may demonstrate compliance with the HCL limit by retaining records of fuel moisture content indicating less than or equal to 1.0 percent by weight. Fuel analyses or supplier guarantee may satisfy this requirement.
   (3) *Hydrogen Fluoride (HF)*. Emissions of HF shall not exceed either 4.0×10^{-4} lb/MMBtu or 4.0×10^{-3} lb/MWh. As an alternative to monitoring and testing, the owner/operator may demonstrate compliance with the HF limit by retaining records of fuel moisture content indicating less than or equal to 1.0 percent by weight. Fuel analyses or supplier guarantee may satisfy this requirement.

   Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUU (see attached Appendix NESHAP, Subpart UUUUU: Coal- and Oil-Fired Electric Utility Steam Generating Units). The permittee shall also comply with the recordkeeping

and reporting requirements specified Subpart UUUUU, as applicable. [40 CFR 63.9991 and Table 2 to Subpart UUUUU]

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The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
005	Unit 3A Gas Turbine 207.4 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
006	Unit 3B Gas Turbine 207.4 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
007	Unit 3C Gas Turbine 207.4 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)
008	Unit 3D Gas Turbine 207.4 MW) with Heat Recovery Steam Generator (495 MMBtu/hr)

Units 3A - 3D, collectively referred to as Unit 3, is a "4-on-1" gas fired combined cycle system. Each of the gas turbines (regulated as Emissions Units 005, 006, 007 & 008) consists of a nominal 207.4 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a heat recovery steam generator (HRSG) each equipped with a 495 MMBtu/hr natural gas fired duct burner, a stack, and associated support equipment. Permit No. 0810010-024-AC/PSD-FL-328E authorized an upgrade for these units to include the DLN 2.6+ combustion system, which is GE's latest evolution of Dry Low-NOx combustion technology. This project also authorized the replacement of various components of the GE Series 7FA.04 gas turbines with upgraded components of the Series 7FA.05 version including (but not limited to) the following: new compressor components; new hot gas path components; new control software; a new Advanced Gas Path (AGP) Performance (Tech Package); and new 3SAR turbine rotors on Units 3A through 3D. Steam from each of the four HRSGs is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle system is 1,299.6 MW.

The units are fired exclusively with natural gas. The efficient combustion of natural gas at high temperatures minimizes emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Nitrogen oxides (NO_X) emissions are reduced by Dry Low-NO_X (DLN) combustion technology (simple cycle mode). A selective catalytic reduction (SCR) system combined with Dry Low-NO_X (DLN) combustion technology further reduces NO_X emissions during combined cycle mode. These emissions units commenced commercial operation in May 2005.

Each gas turbine is equipped with a continuous emissions monitoring system (CEMS) to measure and record CO (optional) and NO_X emissions, as well as flue gas oxygen or carbon dioxide content.

Compliance assurance monitoring (CAM) does not apply since these emissions units have NO_X CEMS which are used to demonstrate continuous compliance.

{Permitting Note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines; Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permit PSD-FL-328 (0810010-006-AC) issued 04/15/03 and PSD-FL-328D (0810010-020-AC). Each stack is 120 feet tall (19 feet diameter). At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1,884 MMBtu lower heating value (LHV) per hour. The exhaust flow rate is 1,004,200 actual cubic feet per minute (acfm) at a temperature of 202° F.}

{Permitting Note: On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines built after January 14, 2003. Unit 3 was under contractual obligations before this date and is therefore an existing unit. Currently, 'existing combustion turbines' are not required to meet the emission limitations, notifications, reporting or any other requirements of Subpart YYYY. EPA may at a future date promulgate standards for existing units.}

<Link to 40 CFR 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines>

Applicable Standards and Regulations

B.1. 40 CFR 60 Subpart A, General Provisions. The owner or operator shall comply with the applicable requirements of 40 CFR 60 Subpart A, General Provisions. For completeness, the applicable Subpart A requirements are included in Appendix NSPS Subpart A of this permit. [Rule 62-204.800, F.A.C.]

B.2. NSPS Subpart KKKK Requirements. The Department determined that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Combustion Turbines in 40 CFR 60, Subpart KKKK. For completeness, the applicable Subpart KKKK requirements are included in Appendix NSPS Subpart KKKK of this permit. [Rule 62-204.800, F.A.C.]

B.3. Gas Turbine Units 3A throughout 3D. The permittee is authorized to operate, tune and maintain the four combustion turbines. Each gas turbine includes the Speedtronic™ automated gas turbine control system. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air cooling system. The gas turbines utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Hot water/electric heaters preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers preheat the natural gas. [PSD-FL-328 (0810010-006-AC, Specific Condition 4.)]

B.4. Gas Turbine Controls.

a. *DLN Combustion Technology*. The permittee is authorized to operate, tune and maintain the General Electric Company DLN-2.6 combustion system to control NO_X emissions from each turbine. The DLN combustors and automated gas turbine control system shall be tuned to operate, tune and maintain a SCR system to control NO_X emissions from each turbine during a combined cycle operation mode. The SCR achieve the simple cycle permitted level for CO and NO_X. Each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. *Selective Catalytic Reduction (SCR) System*. The permittee is authorized to operate, tune and maintain a SCR system to control NO_X emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be operated to achieve the permitted levels for NO_X emissions and ammonia slip.

[PSD-FL-328 (0810010-006-AC, Specific Condition 5.)]

{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions of 40 CFR 68.}

B.5. Heat Recovery Steam Generators. The permittee is authorized to operate and maintain the four heat recovery steam generators (HRSG). Each HRSG is designed to recover heat energy from one of the four gas turbines (3A-3D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG is equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). [PSD-FL-328 (0810010-006-AC, Specific Condition 6.)]

{Permitting Note: The four HRSG units deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}

Essential Potential to Emit (PTE) Parameters

B.6. Gas Turbine Permitted Capacity. The maximum heat input rate to each gas turbine is 1,884 MMBtu/hr (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [0810010-026-AC/PSD-FL-328F, Specific Condition 4.]

B.7. HRSG Duct Burner Permitted Capacity. The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu/hr based on the lower heating value (LHV) of the natural gas. [PSD-FL-328 (0810010-006-AC, Specific Condition 8.)]

B.8. Emissions Unit Operating Rate Limitation During and After Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted

capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. (See also the related testing provisions in Appendix TR, Facility-wide Testing Requirements.) [Rule 62-297.310(3), F.A.C.]

B.9. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

a. *Hours of Operation.* Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year). Restrictions on individual methods of operation are specified below.

b. *Authorized Fuels.* Each gas turbine shall fire natural gas as the primary fuel, which shall contain on average no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.

c. *Combined Cycle Operation.* Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

d. *Combined Cycle Operation with HRSG Duct Firing.* When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input to the duct burners (all four HRSG units) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

e. *Simple Cycle Operation.* Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.
   (1) Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3,390 hours during any consecutive 12 months.
   (2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1,000 hours per unit during any consecutive 12 months.

f. *Inlet Fogging.* In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

g. *Power Augmentation (PA).* When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in this power augmentation mode no more than 400 hours per unit during any consecutive 12 months.

h. *Peaking.* When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

[PSD-FL-328 (0810010-006-AC, Specific Condition 9.)]

Emission Limitations and Standards

B.10. BACT Standards. Emissions from each gas turbine shall not exceed the following standards (see also Specific Condition **B.11.**).

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO [a]	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal Operation	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	10.0, 24-hr
NO_X [b]	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	2.5, 24-hr
		Combined Cycle w/SCR, All Modes	N/A	N/A	2.5, 24-hr
PM/PM_{10} [c]	Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
VOC [e]	Gas	Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia [f]	Gas	Combined Cycle w/SCR	5	NA	NA

Notes:

a. Compliance with the CO standards shall either be demonstrated by stack tests using EPA Method 10 or based on data collected by the optional CEMS. If a CEMS is used, compliance with the 24-hr CO CEMS standard shall be determined separately for each mode of operation based on the hours of operation in each mode. *{Permitting Note: A 24-hr compliance average may be based on as little as 1-hr of data or as much as 24-hr of CEMS data.}*.

b. Compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hr NO_X CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hr compliance average may be based on as little as 1-hr of CEMS data or as much as 24-hr of CEMS data.}*

c. The fuel specifications established in this subsection combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9. *{Permitting Note:*

PM_{10} emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}

d. The fuel sulfur specifications in this subsection effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Specific Condition No. B.30 of this subsection. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Subject to the requirements of this subsection, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027, or CTM-028, or EPA-320.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[PSD-FL-328 (0810010-006-AC, Specific Condition 10.) and 0810010-026-AC/PSD-FL-328F, Specific Condition 2.b.]

B.11. <u>NSPS Subpart KKKK. NSPS 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines Requirements</u>. Except as otherwise provided in this permit, these emissions units shall comply with all applicable provisions of 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, adopted and incorporated by reference in Rule 62-204.800(8)(b), F.A.C., listed below and with all applicable provisions of Appendix 40 CFR 60, Subpart KKKK, included with this permit.

a. *Sulfur dioxide (SO_2) - CT (Subpart KKKK Limits).* The permittee shall comply with either paragraph (1) or (2):

(1) The concentration of SO_2 gasses in the exhaust gas of each CT shall not exceed 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or

(2) Each CT shall not burn any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. if the CT simultaneously fires multiple fuels (each fuel must meet this requirement).

[40 CFR 60.4330(a)(1) & (2) of Subpart KKKK of 40 CFR 60]

b. *Nitrogen Oxides - CT (Subpart KKKK Limits).*

(1) The concentration of NO_X concentrations in the exhaust gas of each CT shall not exceed 15 ppm at 15% O_2, on a 30-unit operating day rolling average, or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)).

(2) The concentration of NO_X concentrations in the exhaust gas of each CT (while operating at less than 75% of peak load) shall not exceed 96 ppm at 15% O_2 on a 30-unit operating day rolling average, or 590 ng/J of useful output (4.7 lb/MWh).

[40 CFR 60.4320, 40 CFR 60.4350(h), and Table 1 to Subpart KKKK of 40 CFR 60]

[Rule 62-204.800(8)(b)82., F.A.C.; and, 0810010-024-AC/PSD-FL-328E, Specific Condition 4.]

B.12. <u>Combined Cycle Operation With Steam Dumped to Condenser</u>. If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR). [PSD-FL-328 (0810010-006-AC, Specific Condition 12.)]

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.13. Operating Procedures. The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSG units, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [PSD-FL-328 (0810010-006-AC, Specific Condition 13.)]

B.14. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

B.15. Alternate Visible Emissions Standard. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [PSD-FL-328 (0810010-006-AC, Specific Condition 15.)]

B.16. Excess Emissions Allowed. As specified in this condition, excess emissions resulting from startup, shutdown, fuel switches, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each gas turbine/HRSG system, excess emissions of NO_X and CO resulting from startup, shutdown, or malfunctions shall be excluded from CEMS data in any 24-hour period for the following conditions. (These conditions are considered separate events and each event may occur independently within any 24-hour period):

a. *Steam Turbine Cold Startup*. For cold startup of the steam turbine, excluded emissions from any gas turbine/HRSG system shall not exceed eight hours in any 24-hour period. Cold startup of the steam turbine shall be completed within twelve hours. A cold "startup of the steam turbine" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine, each gas turbine/HRSG system in the 4-on-1 combined cycle system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine in order to prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

b. *Gas Turbine/HRSG System Cold Startup:* For cold startup of a gas turbine/HRSG system, excluded emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 pounds per square inch gauge (psig) for at least a one-hour period.

c. *Gas Turbine/HRSG System Warm Startup:* For warm startup of a gas turbine/HRSG system, excluded emissions shall not exceed two hours in any 24-hour period (or shall not exceed 8 hours per 4-unit site, with the additional provision of a limit of 2 warm startup periods per 24 hours per gas turbine/HRSG system, in which case excluded emissions shall not exceed eight hours total for the 4-on-1 combined cycle system). "Warm startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum is above 450 psig.

d. *Gas Turbine/HRSG System Shutdown:* For shutdown of the gas turbine/HRSG system operation, excluded emissions from any individual gas turbine/HRSG system shall not exceed two hours in any 24-hour period.

e. *Shutdown Combined Cycle Operation:* For shutdown of the entire 4-on-1 combined cycle system, excluded emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

f. *Documented Malfunction:* For t~~he~~each gas turbine/HRSG system, excess emissions of NO_X and CO resulting from documented malfunctions shall not exceed two hours in any 24-hour period. A

"documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(4), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [0810010-026-AC/PSD-FL-328F, Specific Condition 3.]

B.17. Work Practice Standard and Load Restriction.

a. *Simple Cycle Work Practice BACT*. Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q (i.e., five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

b. *Combined Cycle Work Practice BACT*. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following determination of initial compliance with emission limits when operating in combined cycle mode.

c. *Low-Load Restriction*. Except for startup and shutdown, malfunctions, commissioning and decommissioning, operation at loads where the DLN 2.6 system is not in pre-mix mode is prohibited.

[PSD-FL-328 (0810010-006-AC, Specific Condition 17.)]

B.18. DLN Tuning/FSNL Testing/Green Rotor Run-in. CEMS data collected during initial or other major DLN tuning sessions and during manufacturer required Full Speed No Load (FSNL) trip tests or Green Rotor Run-in periods shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, FSNL, or Green Rotor Run-in activities, the permittee shall provide the Compliance Authority with an advance notice of at least one working (business) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [PSD-FL-328 (0810010-006-AC, Specific Condition 19.); 0810010-018-AC, Specific Condition 3.]

Monitoring of Operations

B.19. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [PSD-FL-328 (0810010-006-AC, Specific Condition 26.)]

Continuous Monitoring Requirements

B.20. CEM Systems. The permittee shall calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO (optional) and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors (if used).* Each CO monitor 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, or Part 75, 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 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NO_x Monitors*. Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR Part 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NO_X monitor span values shall be set approximately considering the allowable method of operation and corresponding emission standards.

c. *Diluent Monitors*. The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR Part 75.

d. *1-Hour Block Averages*. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd, corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO (optional) and NO_X as specified in this permit. For purpose of determining compliance with the CEMS emission standard of this permit, missing (or excluded) data shall not be submitted. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization for Standardization (ISO) conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *24-hour Block Averages.* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *Data Exclusion*. Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, malfunction, and DLN tuning. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Condition No. 16 and 19 of this subsection. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

g. *Availability*. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken

to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department. [PSD-FL-328 (0810010-006-AC, Specific Condition 25., 0810010-018-AC, Specific Condition 4., and 0810010-026-AC/PSD-FL-328F, Specific Conditions 2.e. & 2.f.)]

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart KKKK; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

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.21. Test Methods. Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027; CTM-028; EPA-320	Procedure for Collection and Analysis of Ammonia in Stationary Source *{Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}*
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources *{Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}*
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at: www.epa.gov/ttn/emc/ctm.html. No other methods may be used for compliance testing unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; PSD-FL-328 (0810010-006-AC, Specific Condition 20.)]

B.22. Special Compliance Determinations. The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. Each unit shall be tested under all operating scenarios as required in this permit. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO_X mass emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirement for similar operation in combined cycle mode. [Rule 62-297.310(8)(b)1., F.A.C.; PSD-FL-328 (0810010-006-AC, Specific Condition 21.)]

B.23. Continuous Compliance. The permittee shall demonstrate continuous compliance with the NO_X emissions standards based on data collected by the certified CEMS. The permittee shall demonstrate compliance with the CO emissions standards by stack tests or based on data collected by an optional certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [PSD-FL-328 (0810010-006-AC, Specific Condition 22.) and 0810010-026-AC/PSD-FL-328F, Specific Condition 2.c.]

B.24. Annual Compliance Tests. During each calendar year (January 1st through December 31st), each gas turbine shall be tested to demonstrate compliance with the emission standards for CO (if no CEMS are used), visible emissions and ammonia slip. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS (if used) shall be reported for the visible emissions observation period. [Rule 62-297.310(7)(a)4., F.A.C.; and, PSD-FL-328 (0810010-006-AC, Specific Condition 23.) & 0810010-026-AC/PSD-FL-328F, Specific Condition 2.d.]

*{Permitting Note: Annual compliance tests for VOC emissions are not required. Compliance with the CO standards as specified in Specific Condition **B.23**. shall indicate efficient combustion and low VOC emissions.}*

B.25. Additional Ammonia Slip Testing. If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;
b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and
c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rule 62-297.310(7)(b), F.A.C.; PSD-FL-328 (0810010-006-AC, Specific Condition 24.)]

B.26. 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(7), F.A.C.]

Recordkeeping and Reporting Requirements

B.27. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Malfunction Notification	On occurrence.	**B.32.**
Excess Emissions	Semi-Annually.	**B.33.**

B.28. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

B.29. Monitoring of Capacity. The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [PSD-FL-328 (0810010-006-AC), Specific Condition 27.]

B.30. Monthly Operations Summary. By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption

of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [PSD-FL-328 (0810010-006-AC), Specific Condition 28.]

B.31. Fuel Sulfur Records. The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [PSD-FL-328 (0810010-006-AC), Specific Condition 29.]

B.32. Malfunction Notification. Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports report of the malfunctions. [Rule 62-210.700(6), F.A.C.; PSD-FL-328 (0810010-006-AC), Specific Condition 30.]

B.33. Semi-Annual Excess Emission Report. Within 60 days following the end of each calendar half, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [PSD-FL-328 (0810010-006-AC), Specific Condition 32. and 0810010-026-AC/PSD-FL-328F]

{Permitting Note: This condition pertains to emissions in excess of the PSD emissions limits and state-authorized excludable data periods. There is no prescribed form that must be used for submitting these reports, the required information may be submitted in any format convenient to the facility, but the Department does encourage submittals by electronic mail. Reports of emissions in excess of Subpart KKKK limits shall be submitted in accordance with the requirements of 40 CFR 60, Subparts A and KKKK, as specified in the appendices attached to this permit.}

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This section of the permit addresses the following EU.

EU ID No.	Emission Unit Description
012	Fly Ash Handling, Storage and Shipment System

The design maximum process throughput rates of fly ash resulting from the installation of the ESP are 2,120 pounds per hour (lb/hr) equating to 9,285 TPY of fly ash from each fossil fueled fired steam electric generator unit. The fly ash is stored in two silos each with a storage volume of approximately 6,500 cubic feet (ft^3). Particulate matter (PM) emissions from each silo during loading are controlled by a baghouse (bin vent filter). The fly ash is off loaded to trucks to be transported off site. Approximately two trucks per storage silo per day are used to transport the fly ash off site. Fugitive emissions during truck loading are controlled by the use of vacuum trucks that prevent the release of fugitive emissions during transfer.

*{Permitting Note: Requirements for this emissions unit were established under permit No. 0810010-016-AC, issued June 20, 2011. The fly ash handling system commenced commercial operation in September of 2012. Emissions points/stack parameters and flow rates are described in Specific Condition **C.1**., below.}*

Equipment

C.1. Equipment. The permittee is authorized to operate an ash handling, storage and shipment system EU. The fly ash handling and storage equipment, including both storage silos, have a maximum design transfer rate of approximately 2.12 tons per hour (TPH) with a maximum annual design transfer rate of approximately 18,570 TPY. The overall ash handling, storage and shipment system (EU 012) have a maximum design transfer rate of approximately 66 tons per day (TPD) and approximately 24,100 TPY. This EU consists of the following major equipment components:

a. *Fly Ash Handling.* The fly ash handling equipment consists of totally enclosed hoppers and drop points associated with the collection and transfer of fly ash from the ESP used to control PM emissions from EU 001 and 002 to the storage silos. The fly ash handling equipment is pneumatic.
b. *Fly Ash Storage*. The fly ash storage equipment consists of two storage silos and associated baghouses to control PM emissions.
c. *Fly Ash Shipment.* The fly ash shipment equipment consists of the drop points and chutes associated with the transfer of the fly ash from the storage silo to trucks.

[0810010-016-AC, Specific Condition B.1.]

C.2. Air Pollution Control Equipment. To comply with the emission standards Specific Condition **C.4.**, the permittee shall operate the following air pollution control equipment on the fly ash handling, storage and shipment system EU.

a. *Fly Ash Conveying System.* To the extent practicable, the fly ash conveying system shall be confined and enclosed.
b. *Fly Ash Storage Silos.* Two bin vent filter baghouses shall be operated and maintained to remove PM from the fly ash storage silos exhaust during loading operations. The baghouses shall be designed to achieve a dust outlet loading of 0.015 gr/dscf.

[0810010-016-AC, Specific Condition B.2.]

Performance Restriction

C.3. Hours of Operation. The hours of operation of this EU are not limited (i.e., unrestricted at 8,760 hours per year). [0810010-016-AC, Specific Condition B.3.]

Emissions Standards

C.4. Baghouse Opacity Limit. As determined by EPA Method 9, VE from each baghouse shall not exceed 5% opacity. [0810010-016-AC, Specific Condition B.4.]

Testing and Monitoring Requirements

C.5. Operating Conditions During VE Testing. When required, testing for VE from the baghouse vents (silo and fly ash handling system) shall be conducted while units 1 and/or 2 are firing No. 6 fuel oil and operating at 80% or more of the maximum heat input rate (8,650 MMBtu/hour). [Rule 62-213.440(1), F.A.C.; and, 0810010-016-AC, Specific Condition B.5.]

C.6. Renewal Compliance Tests. Prior to obtaining a renewed Title V air operation permit, each baghouse associated with this EU shall be tested to demonstrate compliance with the opacity standard specified in Specific Condition **C.4.** For the purpose of renewal of an air operation permit, a visible emissions test shall not be required for the baghouse vents if, in the previous five-year period of permitted operation, Units 1 and/or 2 did not burn any liquid fuel or fuel blend for more than 400 hours combined at greater than 80% of their maximum heat input rate, other than during startup, during each calendar year included in the five-year period of permitted operation. The first time Units 1 and/or 2 subsequently burns any liquid fuel or fuel blend for more than 400 hours combined at greater than 80% of their maximum heat input rate during a calendar year, visible emissions from the baghouse vents must be tested no later than 60 days after burning of any liquid fuel or fuel blend in Units 1 and/or 2 exceeds 400 hours in that calendar year, or by the end of that calendar year, whichever is later. [Rules 62-213.440(1) & 62-297.310(8)(b)3.d., F.A.C.; and, 0810010-016-AC, Specific Condition B.7.]

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

Method	Description of Method and Comments
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources, 30 Minute Duration

[0810010-016-AC, Specific Condition B.8.]

Recordkeeping and Reporting Requirements

C.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 this permit. [Rule 62-297.310(7), F.A.C.]

C.9. Baghouse Records. The permittee shall maintain records of the baghouse design specification for the outlet dust loading limit of 0.015 gr/dscf. Replacement bags shall meet this design specification. [0810010-016-AC, Specific Condition B.10.]

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Subsection D. Emissions Unit 014

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

E.U. ID No.	Brief Description
014	Emergency Diesel-Fired Fire Pump Engine

The unit is a diesel fuel-fired engine-driven fire pump, manufactured by John Deere, Model 6081HF001-J, 268 HP, in service 2004, with 6 cylinders and 8.1 liters total displacement.

This emissions unit is a diesel-fired reciprocating internal combustion engine (RICE) used to drive an emergency fire pump. The emergency fire pump engine uses ultra-low sulfur fuel oil only.

The following table provides important details for the above emission unit:

Engine Brake HP	Date of Construction	Primary Fuel	Displacement liters/cylinder (l/c)	Serial Number	Applicable Requirements for Compression Ignition Type Engines
268 HP	2004	Diesel	1.35	Unknown	40 CFR 63, Subparts A and ZZZZ This engine is an 'existing' unit.

{Permitting Note: This compression ignition (CI) engine used to drive this emergency fire pump is regulated under 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE adopted in Rule 62.204.800(11)(b), F.A.C. Because this engine qualifies as an existing stationary RICE less than 500 HP operating at a major source of HAP, it is not subject to regulation under NSPS 40 CFR 60, Subpart IIII. Stack parameters: stack height = 6 feet, exit diameter = 3 inches, exit temperature = 250° F, actual volumetric flow rate = 600 acfm.}

<Link to 40 CFR 63, Subpart ZZZZ - NESHAP for Stationary Reciprocating Internal Combustion Engines>

Essential Potential to Emit (PTE) Parameters

D.1. Hours of Operation.

a. *Emergency Situations*. There is no time limit on the use of this fire pump engine in emergency situations. [40 CFR 63.6640(f)(1)]

b. *Maintenance and Readiness Testing*. This engine is authorized to operate for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Operation for maintenance checks and readiness testing is limited to 100 hours per year. [40 CFR 63.6640(f)(2)(i)]

c. *Non-emergency Situations*. This engine is authorized to operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. [40 CFR 63.6640(f)(2)(iii)]

Emission Limitations and Operating Requirements

D.2. Work or Management Practice Standards.

a. *Oil*. Change oil and filter every 500 hours of operation or annually, whichever comes first. [40 CFR 63.6602 & Table 2c.1.a.]

b. *Air Cleaner*. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6602 & Table 2c.1.b.]

c. *Hoses and Belts*. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6602 & Table 2c.1.c.]

d. *Operation and Maintenance*. Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions or develop and follow your own maintenance plan which must provide, to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e) & Table 6.9.].

e. *Engine Startup*. During periods of startup the owner or operator must minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the

engine, not to exceed 30 minutes. [40 CFR 63.6625(h)]

f. *Oil Analysis*. The owner or operator has the option of using oil analysis to extend the oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in paragraph a., of this condition. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

Monitoring of Operations

D.3. Hour Meter. The owner or operator must install a non-resettable hour meter if one is not already installed. [40 CFR 63.6625(f)]

Compliance

D.4. Continuous Compliance. Each unit shall be in compliance with the operating standards in this section at all times. [40 CFR 63.6605(a)]

D.5. Operation and Maintenance of Equipment. At all times the owner or operator must operate and maintain, any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the compliance authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Recordkeeping and Reporting Requirements

D.6. Notification, Performance and Compliance Records. The owner or operator must keep:

a. A copy of each notification and report that the owner or operator submitted to comply with this section, including all documentation supporting any Initial Notification or Notification of Compliance Status that the owner or operator submitted.
b. Records of the occurrence and duration of each malfunction of operation.
c. Records of all required maintenance performed on the hour meter.
d. Records of actions taken during periods of malfunction to minimize emissions in accordance with Specific Condition **D.5.**, including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation.
e. Records of the actions required in specific condition **D.2.d.** to show continuous compliance with each emission limitation or operating requirement.
f. Records of the Work or Management Practice Standards specified in Specific Condition **D.2.**
g. Records of the maintenance conducted in order to demonstrate that the RICE was operated and maintained according to your own maintenance plan.
h. Records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for emergency demand response operation or for periods of voltage or frequency deviations, the owner or operator must keep records of the notification of the emergency situation, and the time of engine operation for these purposes.

[40 CFR 63.6655]

D.7. Record Retention.

a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.

b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660 and 40 CFR 63.10(b)(1)]

D.8. Delay of Performing Work Practice Requirements. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in specific condition **D.2.** of this section, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. [40 CFR 63, Subpart ZZZZ, Table 2c, footnote 1]

Other Federal Requirements

D.9. 40 CFR 63 Subpart A - General Provisions. The owner or operator shall comply with the following applicable requirements of 40 CFR 63 Subpart A - General Provisions, which have been adopted by reference in Rule 62-204.800(11)(d)1., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 63.5(e), 40 CFR 63.5(f), 40 CFR 63.6(g), 40 CFR 63.6(h)(9), 40 CFR 63.6(j), 40 CFR 63.13, and 40 CFR 63.14. Link to 40 CFR 63, Subpart A - General Provisions

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (Additional terms defined in §63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)–(5)	Initial notifications (Except that §63.9(b)(3) is reserved)
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination
§63.10(d)(1)	General reporting requirements
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

[40 CFR 63.6665]

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Subsection E. Emissions Unit 003

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

ID No.	Emission Unit Description
003	One 1,000 kW Diesel Engine-driven Emergency Engine

This unit is an emergency 12-cylinder, 32.10 liter, diesel engine-driven generator for Units 1 and 2. This engine fires ultra-low sulfur diesel fuel.

The following table provides important details for this engine.

Engine Identification	Engine Brake HP	Date of Manufacture	Model Year	Displacement liters/cylinder (l/c)	Engine Manufacturer	Model No.
Emergency Diesel Engine	1,341 (1,000 kW)	December 2011	2010	2.68	Caterpillar	EMCP 4 Series; Model C32

{Permitting Notes: This compression ignition reciprocating internal combustion engine (CI RICE) is regulated under 40 CFR 63, Subpart ZZZZ, NESHAP for Stationary RICE and 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition RICE, adopted in Rules 62.204.800(11)(b) & (8)(b), F.A.C., respectively. This is a "new" stationary emergency CI RICE with a displacement of less than 10 liters per cylinder, located at a major source of HAP, that commenced construction on or after 6/12/2006, and that has a post-2007 model year. In accordance with provisions of 40 CFR 63.6590(c)(6), meeting the requirements of 40 CFR 60, Subpart IIII, satisfies compliance with the requirements of Subpart ZZZZ. Stack parameters: stack height = 16 feet, exit diameter = 1.2 feet, exit temperature = 710° F, actual volumetric flow rate = 10,770 acfm.}

<Link to 40 CFR 60, Subpart IIII - NSPS for Stationary Compression Ignition Internal Combustion Engines>

Essential Potential to Emit (PTE) Parameters

E.1. Authorized Fuel. This Stationary Reciprocating Internal Combustion Engine (RICE) must use diesel fuel that meets the following requirements for non-road diesel fuel:

a. *Sulfur Content*. The sulfur content shall not exceed = 15 ppm = 0.0015% by weight (ultra-low sulfur) for non-road fuel.

b. *Cetane and Aromatic*. The fuel must have a minimum cetane index of 40 or must have a maximum aromatic content of 35 volume percent.

c. *Use of Existing Fuel*. Any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

[40 CFR 60.4207(b), 80.510(c), 80.510(f)(2) & 80.510(f)(7)]

E.2. Restricted Hours of Operation.

a. *Maintenance and Testing*. This engine is authorized to operate for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year.

b. *Emergency Situations*. There is no time limit on the use of emergency stationary RICE in emergency situations.

c. *Non-emergency Situations*. This engine may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing.

d. *Other Situations*. This engine cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity.

[40 CFR 60.4211(f)]

E.3. Operation and Maintenance. Except as permitted in Specific Condition **E.8.**, the owner or operator must operate and maintain the stationary CI internal combustion engine according to the manufacturer's written

instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. These RICE must be maintained and operated to meet the emissions limits in Specific Conditions **E.4. - E.6.** over the entire life of the engine. [40 CFR 60.4206, 4211(a)(1), (2) & (3)]

Emissions Standards

E.4. NO_X + NMHC Emissions. Emissions of NO_X plus non-methane hydrocarbons shall not exceed 6.4 grams per kilowatt hour (g/kW-hr). [40 CFR 60.4205(b), 40 CFR 60.4202(a)(2) & 40 CFR 89.112(a).

E.5. CO Emissions. Carbon monoxide (CO) emissions shall not exceed 3.5 g/kW-hr. [40 CFR 60.4205(b), 40 CFR 60.4202(a)(2) & 40 CFR 89.112(a)]

E.6. PM Emissions. Particulate matter (PM) emissions shall not exceed 0.2 g/kW-hr. [40 CFR 60.4205(b), 40 CFR 60.4202(a)(2) & 40 CFR 89.112(a)]

Testing and Compliance Requirements

E.7. Engine Certification Requirements. The owner or operator must comply with the emissions standards specified above by having purchased an engine certified by the manufacturer to meet those limits. The engine must have been installed and configured according to the manufacturer's emission-related specifications, except as permitted in Specific Condition **E.8.** [40 CFR 60.4211(c)]

E.8. Compliance Requirements Due to Loss of Certification. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards. [40 CFR 60.4211(g)(3)]

E.9. Testing Requirements. In the event performance tests are required pursuant to Specific Condition **E.8.**, the following requirements shall be met:

a. *Testing Procedures*. The performance test must be conducted according to the in-use testing procedures in 40 CFR Part 1039, Subpart F. Link to Subpart F

b. *NTE Standards*. Exhaust emissions from these engines must not exceed the not-to-exceed (NTE) numerical requirements, rounded to the same number of decimal places as the applicable standard (STD) in Specific Conditions **E.4.**, **E.5.** and **E.6.**, determined from the following equation:
NTE Requirement for Each Pollutant = (1.25) x (STD) (Eq. 1)

[40 CFR 60.4212(a) & (c)]

E.10. Common Testing Requirements. Unless otherwise specified and if required, 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.]

Monitoring Requirements

E.11. Hour Meter. The owner or operator must install a non-resettable hour meter if one is not already installed. [40 CFR 60.4209(a)]

Records and Reports

E.12. Hours of Operation Records. The owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner or operator must record the time of operation of the engine and the reason the engine was in operation during that time. [40 CFR 60.4214]

E.13. Maintenance Records. To demonstrate conformance with the manufacturer's written instructions for maintaining the certified engine and to document when compliance testing must be performed pursuant to Specific Condition **E.8.**, the owner or operator must keep the following records:

a. Engine manufacturer documentation and certification indicating compliance with the standards.
b. A copy of the manufacturer's written instructions for operation and maintenance of the certified engine.
c. A written maintenance log detailing the date and type of maintenance performed on the engine, as well as any deviations from the manufacturer's written instructions.

[Rule 62-213.440(1), F.A.C.]

E.14. Testing Notification. At such time that the requirements of Specific Condition **E.8.** become applicable, the owner or operator shall notify the compliance authority of the date by which the initial compliance test must be performed. [Rule 62-213.440(1)]

E.15. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

General Provisions

E.16. 40 CFR 60 Subpart A, General Provisions. The owner or operator shall comply with the applicable requirements of 40 CFR 60 Subpart A, General Provisions, as specified below. Link to 40 CFR 60, Subpart A - General Provisions.

General Provisions Citation	Subject of Citation
§ 60.1	General applicability of the General Provisions
§ 60.2	Definitions (see also § 60.4219)
§ 60.3	Units and abbreviations
§ 60.4	Address
§ 60.5	Determination of construction or modification
§ 60.6	Review of plans
§ 60.9	Availability of information
§ 60.10	State Authority
§ 60.12	Circumvention
§ 60.14	Modification
§ 60.15	Reconstruction
§ 60.16	Priority list
§ 60.17	Incorporations by reference
§ 60.19	General notification and reporting requirements

[40 CFR 60.4218]

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Operated by: Florida Power and Light Company
ORIS Code: 6042

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

E.U. ID No.	EPA Unit ID #	Brief Description
001	PMT1	Fossil Fuel Steam Generator, Unit 1
002	PMT2	Fossil Fuel Steam Generator, Unit 2
005	MTCT3A	Unit No. 3A Gas Turbine (nominal 207.4 MW) with Heat Recovery Steam Generator
006	MTCT3B	Unit No. 3B Gas Turbine (nominal 207.4 MW) with Heat Recovery Steam Generator
007	MTCT3C	Unit No. 3C Gas Turbine (nominal 207.4 MW) with Heat Recovery Steam Generator
008	MTCT3D	Unit No. 3D Gas Turbine (nominal 207.4 MW) with Heat Recovery Steam Generator

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. Form No. 62-210.900(1)(a), dated 02/27/13, received 05/07/13.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

2. 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.]

3. Comments, notes, and justifications: None.

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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 X Renewal

STEP 1

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

Plant name ; **MANATEE**	State **Florida**	**006042** 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
PMT1	**NO**	**Yes**		
PMT2	**NO**	**Yes**		
MTCT3A	**NO**	**Yes**		
MTCT 3B	**NO**	**Yes**		
MTCT 3C	**NO**	**Yes**		
MTCT 3D	**NO**	**Yes**		

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

1

Plant Name (from STEP 1) **MANATEE**

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,

Plant Name (from STEP 1) **MANATEE**

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

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Plant Name (from STEP 1) MANATEE

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 12/20/17

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.

Name **Christian Kiernan** | Title **Environmental Services Director/Designated Representative**

Owner Company Name **Florida Power & Light**

Phone **561-691-2781** | E-mail address: **christian.kiernan@fpl.com**

Signature | Date 12/20/17

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