



**FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION**
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Duke Energy Florida, Inc.
University of Florida Cogeneration Plant
1928 Mowery Road, Building 82
Gainesville, FL 32611-2295

Authorized Representative:

Brian V. Powers, Station Manager

Air Permit No. 0010001-014-AC
PSD-181C

University of Florida Cogeneration Plant
Facility ID No. 0010001

Boiler Replacement Project

PROJECT

This is the final permit authorizing the construction of a new steam boiler to replace the existing Boiler No. 4 (EU 002) at the UF Cogeneration (CoGen) Plant. The new boiler will support the steam load requirements of the UF. The UF CoGen Plant address is 1928 Mowry Road, Building 82, Gainesville, Florida 32611. The UTM coordinates are Zone 17, 369.39 kilometers (km) East, and 3279.29 km North. The facility is an electrical power generating plant with a Standard Industrial Classification Code (SIC) of No. 4911.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); Section 4 (Appendices).

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

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

FINAL PERMIT

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this final air permit package (including the Final Determination and Final Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on the date indicated below to the following persons.

Mr. Brian V. Powers, Duke Energy Florida, Inc.: Brian.Powers@duke-energy.com

Mr. Chris Bradley, Duke Energy Florida, Inc.: Chris.Bradley@duke-energy.com

Mr. Scott Osbourn, PE, Golder Associates: scott_osbourn@golder.com

Mr. Richard Rachal, Northeast District Office: Richard.Rachal@dep.state.fl.us

Ms. Kathleen Forney, EPA Region 4: forney.kathleen@epa.gov

Ms. Lynn Scearce, DEP: lynn.scearce@dep.state.fl.us

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

SECTION 1. GENERAL INFORMATION (FINAL)

FACILITY AND PROJECT DESCRIPTION

Existing Facility

The UF CoGen Plant consists of one nominal 48 megawatt General Electric LM6000-PC-ESPRINT Combustion Turbine (CT) with one Heat Recovery Steam Generator (HRSG) and Duct Burner (DB) system comprising a combined cycle unit. In addition, there are two Backup Steam Boilers. The CT uses spray inter-cooling to maximize power generation and reduce the need for supplemental firing of the DB system to meet steam and power requirements. Emissions from the CT and DB system are vented through the HRSG stack. Emissions of nitrogen oxides (NO_x) are controlled with steam injection and compliance is demonstrated by data collected from a continuous emissions monitoring system (CEMS). Each backup steam boiler has a separate exhaust stack and is used only as a backup source of steam when the combined cycle system is not available or to provide supplemental steam during periods of high steam demand.

A summary of the regulated existing emission units and corresponding emissions unit identification numbers (E.U. ID No.) within the Department’s Air Resource Management System (ARMS) at the UF CoGen Plant is given below. The emission unit affected by this permitting action is highlighted in **turquoise** in the table.

Facility ID No. 0010001	
EU ID No.	Emission Unit Description
002	No. 4 Backup Steam Boiler (to be replaced)
003	No. 5 Backup Steam Boiler
005	Heat Recovery Steam Generator with Duct Burner System
007	Combustion Turbine, General Electric Model No. LM6000-PC-ESPRINT

Proposed Project

This project involves the construction of a new steam boiler to replace the existing Backup Steam Boiler No. 4 (EU 002) at the UF CoGen Plant. The new boiler will support the steam load requirements of the UF when the combined cycle system is not available or to provide supplemental steam during periods of high steam demand. UF is planning to replace Boiler No. 4, which is permitted at 69.6 million British thermal units per hour (MMBtu/hr) and 40,000 pounds per hour (lb/hr) of steam, with the new boiler with a heat input of 99.9 MMBtu/hr and capacity to produce approximately 78,500 lb/hr of steam. UF will purchase and install the boiler, which is proposed to be a Cleaver Brooks Company model NB-300D-70, and Duke Energy Florida (DEF) will operate the boiler.

The new emission unit resulting from this project will be assigned the following E.U. ID No. within the Department’s ARMS:

New EU ID No.	Description
008	New Backup Steam Boiler No. 6 <ul style="list-style-type: none"> • Heat Input: 99.9 MMBtu/hr • Steam Generation: 78,500 lb/hr

FACILITY REGULATORY CLASSIFICATION

- The facility **is not** a major source of hazardous air pollutants (HAP).
- The facility has units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

SECTION 1. GENERAL INFORMATION (FINAL)

- This project (as discussed below) **does not** trigger a PSD review and a requirement to conduct Best Available Control Technology (BACT) determinations pursuant to Department Rule 62-212.400, F.A.C.
- The proposed project includes units subject to Clean Air Interstate Rule (CAIR).
- The proposed project includes units subject to the New Source Performance Standards (NSPS) of Title 40 Code of Federal Regulations (CFR) Part 60.
- The proposed project includes units subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

SECTION 2. ADMINISTRATIVE REQUIREMENTS (FINAL)

1. Permitting Authority: The Permitting Authority for this project is the Office of Permitting and Compliance (OPC) in the Division of Air Resource Management of the Department. The mailing address for the OPC is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the OPC Section.
2. Compliance Authority: All documents related to compliance activities such as reports, tests and notifications shall be submitted to the Northeast District Office. The mailing address and phone number of the Northeast District Office is: 8800 Baymeadows Way West, Suite 100, Jacksonville, Florida 32256-7590, (904) 256-1700.
3. Appendices: The following Appendices are attached as part of this permit:
 - a. Appendix A. Citation Formats and Glossary of Common Terms;
 - b. Appendix B. General Conditions;
 - c. Appendix C. Common Conditions;
 - d. Appendix D. Common Testing Requirements;
 - e. Appendix Subpart A. NSPS Subpart A and NESHAP Subpart A - Identification of General Provisions;
 - f. Appendix Dc. NSPS 40 CFR Part 60 - Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; and
 - g. Appendix GG. NSPS 40 CFR 60, Subpart GG - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification.
[Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. For good cause, the permittee may request that this air construction permit be extended. Such a request shall be submitted to the Office of Permitting and Compliance at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]
8. Source Obligation:
 - a. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

SECTION 2. ADMINISTRATIVE REQUIREMENTS (FINAL)

- b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.
- c. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

- 9. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to each Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]
- 10. Annual Operating Report (AOR): The owner or operator shall submit an AOR for the Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) to the Department annually pursuant to subsection 62-210.370(3), F.A.C.
- 11. Shutdown of Existing Backup Steam Boiler No. 4: Upon commercial operation of the new Backup Steam Boiler No. 6 (EU 008), the existing Backup Steam Boiler No. 4 shall no longer be used to provide steam generation to the UF. [Application 0010001-014; Rules 62-210.200 (Potential to emit) and 62-4.030, F.A.C.]

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
003	No. 5 Backup Steam Boiler
005	Heat Recovery Steam Generator with Duct Burner System
007	Combustion Turbine, General Electric Model No. LM6000-PC-ESPRINT
008	New Backup Steam Boiler No. 6

The steam boilers (EU 003 and 008) are to be used as back-up sources of steam or to provide supplemental steam during periods of high steam demand. Each boiler will/or has its own exhaust stack. The maximum design heat input rate for the No. 5 steam boiler is 168 MMBtu/hour based on firing 164,000 cubic feet of natural gas per hour and 1,067 gallons per hour of No. 2 fuel oil. The No. 5 steam boiler has a stack height of 82 feet, exit diameter of 6 feet, exit temperature of 400 °F and actual volumetric flow rate of 56,250 acfm. The steam boiler No. 5 began commercial service in January 1976.

The combined cycle system (EU-005 and 007) consists of a nominal 48 MW CT and a HRSG with a DB system. The CT is fired with natural gas and utilizes spray inter-cooling to maximize power output, which reduces the need for supplemental firing of the DB system to meet steam and power requirements. Steam injection is used to control NO_x emissions from the combustion turbine. The DB system is equipped with low-NO_x burners to control NO_x emissions while firing natural gas. Exhaust gas from the combined cycle system exits the HRSG stack at a height of 93 feet, exit diameter of 9.8 feet, exit temperature of 257 °F and actual volumetric flow rate of 365,700 acfm, based on the CT only at a compressor inlet temperature of 59 °F, 60% relative humidity at inlet, maximum dry standard flow rate of 216,956 dscfm and exit velocity of 80.8 feet per second. Originally, a 43 MW CT (GE LM6000-PA) began commercial service on January 31, 1994. It was replaced with new 48 MW unit (GE LM6000-PC-ESPRINT) with spray inter-cooling, which began commercial service on September 24, 2002.

{Permitting Note: This facility was permitted originally in 1992 to provide electrical power and steam for the University of Florida. The original project (PSD-FL-181) authorized the construction of the cogeneration facility and required the permanent shutdown of Boilers Nos. 1, 2 and 3. In accordance with Rule 62-212.400(PSD), F.A.C., the above emission units are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO).}

OTHER PERMITS

1. New Permit: This permit supersedes all previous air construction permits for the specified emissions units at the cogeneration plant. The conditions of the new permit are based upon Application No. 0010001-014-AC as well as previous applications for the original Permit No. PSD-FL-181 as well as subsequent modifications and amendments. [Rule 62-4.070(3), F.A.C.]

SHUTDOWN UNITS

2. Shutdown Units: Boiler No. 4 shall be permanently shut down as a part of this project. [Rule 62-212.400(12), F.A.C.]

APPLICABLE STANDARDS AND REGULATIONS

3. NSPS Requirements: The new backup Steam Boiler No. 6 (EU 008) along with existing emission units shall comply with all applicable requirements in NSPS in 40 CFR 60, Subpart A (General Provisions). In addition the new boiler shall comply with all applicable requirements of 40 CFR 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units). The existing duct burner and HRSG (EU 005) shall comply with all applicable requirements in NSPS 40 CFR 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units). The existing CT

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

(EU 007) shall comply with all applicable requirements in NSPS 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). See Appendices Subpart A, Db, Dc and GG of this permit. [Rule 62-204.800(7)(b), F.A.C.; and NSPS 40 CFR 60, Subparts A, Db, Dc and GG]

4. State Requirements: The backup steam boilers are regulated under this permit and Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 MMBtu per Hour Heat Input. [Rule 62-296.406, F.A.C.]

NEW EQUIPMENT

5. New Backup Steam Boiler No. 6 (EU 008): The permittee is authorized to install, tune, operate, and maintain one Cleaver Brooks Company model NB-300D-7 boiler or other vendor equivalent to provide backup steam to the UF. The boiler will be designed for dual-fuel capability (natural gas and No. 2 fuel oil with a maximum sulfur content of 0.1%). The boiler will have a nominal heat input of 99.9 MMBtu/hr based on firing 97,941 cubic feet of natural gas per hour and 723 gallons per hour of No. 2 fuel oil with nominal capacity to produce approximately 78,500 lb/hr of steam. The new Backup Steam Boiler No. 6 will have a nominal stack height of 82 feet, exit diameter of 5 feet, exit temperature of 302 °F and an actual volumetric flow rate of 28,170 actual cubic feet per minute (acfm). [Application 0010001-014-AC; Design]
6. Boiler Pollution Control Equipment: The new Backup Steam Boiler No. 6 shall utilize low NO_x burners and flue gas recirculation to minimize emission of NO_x. [Application 0010001-014-AC; Design; Rule 62-210.200(PTE), F.A.C.]

EXISTING EQUIPMENT

7. Combined Cycle Combustion Turbine System: The permittee is authorized to operate and maintain as combined cycle combustion turbine system consisting of a nominal 48 MW combustion turbine (GE LM6000-PC-ESPRINT) and a heat recovery steam generator with duct burner. The combustion turbine system generally consists of the following components: gas generator, accessory drive system, air inlet and filtration system, fuel delivery system, cooling system, lubrication system, control system, starting system and exhaust system with stack. This aero-derivative gas turbine is designed with modular components to facilitate quick repairs. Common “wear items” include compressor vanes, turbine nozzles, compressor blades, turbine blades, fuel nozzles, combustion chambers, seals, and shaft packing. The concept of modular design extends to the complete replacement of major components of the gas turbine. Replacements are authorized provided the following requirements are met.
 - a. The “hot section” components (e.g., combustors and high-speed turbines including blades, nozzles and other components) shall be replaced with equivalent “like-kind” equipment. Replacement components shall not increase the maximum heat input rate, capacity or emissions from the combustion turbine. Replacement components shall be designed to achieve and shall achieve the emissions standards specified in this permit or better.
 - b. Within 90 days of replacing a gas turbine, the permittee shall conduct emissions stack tests to demonstrate compliance with the emission standards for CO and visible emissions. The permittee shall comply with the requirements for notification, test methods, test procedures, and reporting required by this permit.
 - c. To up-rate the gas turbine or increase the maximum heat input rate or capacity, the permittee shall submit an application for an air construction permit.
[Application and Design]
8. Combustion Turbine – Steam Injection: A steam injection system shall be used to reduce NO_x emissions from the combustion turbine exhaust. In accordance with 40 CFR 60.334, the permittee shall operate a continuous monitoring system to monitor and record the ratio of steam to fuel being fired in the combustion turbine. The permittee shall establish the steam-to-fuel ratio that demonstrates compliance with the emissions standards of this permit by correlating with data collected by the NO_x CEMS. When the NO_x CEMS is

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

down, the permittee shall operate at a steam-to-fuel injection rate that demonstrates compliance. [Rule 62-4.070(3), F.A.C. and NSPS Subpart GG in 40 CFR 60]

9. Existing Backup Steam Boiler No. 5: The permittee is authorized to operate and maintain Backup Steam Boiler No 5 to provide a source of steam in case the combustion turbine is unavailable or to provide supplemental steam during periods of high steam demand. [Application and Design]

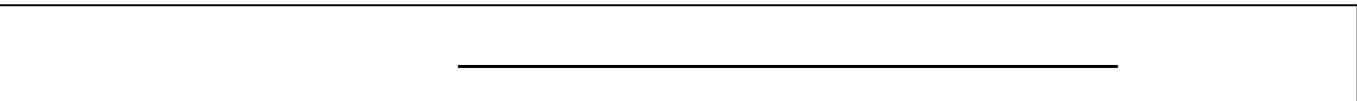
PERFORMANCE RESTRICTIONS

10. Permitted Capacities:

- a. *Combustion Turbine*: The heat input to the combustion turbine shall not exceed the values defined by the manufacturer’s performance curve of heat input rate vs. compressor inlet temperature. The maximum heat input limits are based on the lower heating value (LHV) of natural gas, 100% load and ambient conditions of 60% relative humidity and 14.7 psia. The maximum heat input rates will vary depending upon ambient conditions, the combustion turbine characteristics and the demand. {*Permitting Note: The maximum design heat input rate to the combustion turbine is 480 MMBtu/hour for a compressor inlet temperature of 59 °F.*}
- b. *Duct Burner*: The maximum design heat input to the duct burner system is 188 MMBtu/hour of natural gas. The duct burner shall not fire more than 519.5 million ft³/year of natural gas based on the lower heating value (LHV) of 950 Btu/ft³.
- c. *Backup Steam Boiler No. 5*: When either firing natural gas or No. 2 fuel oil, the maximum design heat input rate for the No. 5 steam boiler is 168 MMBtu/hour (equivalent to 164,000 cubic feet of natural gas per hour or 1067 gallons per hour of No. 2 fuel oil).

[Application, Design and Rule 62-210.200(PTE), F.A.C.]

11. Authorized Fuels: The combustion turbine, HRSG, duct burners and backup steam boilers are authorized to fire natural gas with a maximum sulfur content of 2 grains of sulfur per 100 scf (annual average based on vendor data). The backup steam boiler No. 5 is authorized to fire No. 2 fuel oil with a maximum sulfur content of 0.5% by weight while backup steam boiler No. 6 is authorized to fire No. 2 fuel oil with a maximum sulfur content of 0.1% by weight (annual average based on vendor data). [Rules 62-210.200(PTE), 62-212.400(12), 62-296.406, F.A.C., and 40 CFR 60.333(b)]
12. Restricted Operation CT and Backup Steam Boiler No. 5: The hours of operation for the CT and Backup Steam Boiler No. 5 are not limited (8,760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
13. Restricted Operation New Backup Boiler No. 6: The hours of operation while firing natural gas in Backup Steam Boiler No. 6 is not limited (8,760 hours per year). When natural gas is available, backup boiler No. 6 is limited to firing fuel oil to no more than a combined total of 48 hours during any calendar year except during periods of natural gas supply curtailment or interruption. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C; NESHP 40 CFR 63, Subpart JJJJJ.]
14. Gas Curtailment: During times of gas curtailment, the new backup boiler No. 6 may fire fuel oil for the number of operational hours determined by the below equations. Because the UF CoGen site is supplied by a single natural gas pipeline examples of periods of gas interruptions include, pressure testing of the gas supply pipeline, maintenance and repair of gas valves and gas leak repair. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C; NESHP 40 CFR 63, Subpart JJJJJ.]



SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

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Annual NO_x emissions from the backup steam boilers shall be determined based on the annual fuel consumption rates and the appropriate NO_x emissions factors (see **Specific Condition 29** of this subsection).

** CT emissions include emissions from the duct burner system and shall be determined by data collected from the NO_x CEMS (see **Specific Condition 29** of this subsection).

EMISSIONS STANDARDS

15. Emissions Standards – Combined Cycle Combustion Turbine with Duct Burner:

a. Carbon Monoxide (CO) Emissions:

(1) As determined by EPA Method 10, CO emissions from the combustion turbine shall not exceed 36.0 ppmvd corrected to 15% oxygen. {Permitting Note: This is equivalent to 35.8 lb/hour at a compressor inlet temperature of 59 °F.}

(2) As determined by EPA Method 10, CO emissions from the duct burner shall not exceed 0.15 lb/MMBtu and 28.1 lb/hour.

[Rule 62-212.400(BACT), F.A.C.]

b. Nitrogen Oxides (NO_x) Emissions:

(1) As determined by CEMS, NO_x emissions from the combustion turbine shall not exceed 39.6 lb/hour with the duct burner “off” and 58.3 lb/hour with the duct burner “on”, based on 30-day rolling averages. {Permitting Note: The basis for the NO_x limit on the combustion turbine is 25 ppmvd corrected to 15% oxygen as provided by the vendor.} [PSD avoidance pursuant to Rule 62-212.400(12), F.A.C.]

(2) As determined by CEMS, NO_x emissions from the combustion turbine shall not exceed the applicable NSPS emissions standard in 40 CFR 60.332:

(14.4)

STD = 75 ppmvd corrected to 15% oxygen ----- = 123 ppmvd corrected to 15% oxygen (8.8)

where:

STD = allowable NO_x emissions standard corrected to ISO conditions based on a 4-hour rolling CEMS average [40 CFR 60.334]

Y = 8.8 kilojoules per watt hour (kJ/W-hr) based on 950 Btu/SCF (LHV) for natural gas, which is the manufacturer’s rated heat rate at manufacturer's rated load (kilojoules per watt-hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kJ/W-hr.

There is no NO_x emission allowance for fuel-bound nitrogen for natural gas.

[40 CFR 60.334]

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

(3) As determined by CEMS data pursuant to 40 CFR 60.46b, NO_x emissions from the duct burner shall not exceed 0.1 lb/MMBtu and 18.7 lb/hour based on 30-day rolling average. [40 CFR 60.44b and original Permit No. PSD-FL-181]

- c. *Sulfur Dioxide (SO₂) Emissions:* SO₂ emissions from the combustion turbine shall be controlled by firing natural gas with a maximum sulfur content of 2 grains of sulfur per 100 standard cubic feet of natural gas. This condition also ensures that the fuel contains less than 0.8% by weight pursuant to 40 CFR 60.333(b). [Rules 62-212.400(12) and 40 CFR 60.333]
- d. *Visible Emissions:* As determined by EPA Method 9, visible emissions shall not exceed 10% opacity from the combustion turbine with or without the duct burner in operation. [Rule 62-4.070(3), F.A.C.]

16. Emissions Standards – Backup Steam Boiler No. 5: To control PM and SO₂ emissions, the backup steam boiler No. 5 shall fire only natural gas or No. 2 fuel oil with a maximum sulfur content of 0.5%. As determined by EPA Method 9, visible emissions when firing any authorized fuel shall not exceed 20% opacity except for one, 6-minute block average per hour not to exceed 27% opacity. [Rule 62-296.406(BACT) and 62-296.406, F.A.C.]

17. Emission Standards – Backup Steam Boiler No. 6: Backup Steam Boiler No. 6 shall meet the following emission limits:

Pollutant	Fuel ¹	lb/MMBtu ²	lb/hr	Basis	Compliance Method
NO _x	Natural Gas	N/A ³	3.64	Rule 62-210.200(PTE), F.A.C.	Annual Stack Test
	Fuel Oil		12.6		
SO ₂	Fuel Oil	050	N/A	NSPS Subpart Dc	
PM		0.03		NSPS Subpart Dc and NESHAP Subpart JJJJJ	
Opacity ⁴	Fuel Oil	20/27		NSPA Subpart Dc	
	Natural Gas		Rule 62-296.406, F.A.C.		
1. Fuel oil limits only apply when oil is fired in backup boiler No. 6 for more than 48 hours in a calendar year excluding periods of gas supply curtailment and interruptions. 2. Opacity limits are in percent (%) visible emissions (VE). 3. .N/A = not applicable. 4. VE when firing any authorized fuel shall not exceed 20% opacity except for one, 6-minute block average per hour not to exceed 27% opacity					

[Rules 62-4.070(3); 62-210.200(PTE) and 62-296.406, F.A.C.; NSPS Subpart Dc and NESHAP 40 CFR 63, Subpart JJJJJ.]

18. Facility-Wide Annual NO_x Emission Cap: NO_x emissions shall not exceed 185.3 tons per year for any calendar year for all emissions units regulated by this air construction permit (EU 003, 005, 007 and 008). The backup steam boilers may operate individually or in combination with one another or in combination with the CT/HRSG for supplemental steam during periods of high steam demand provided NO_x emissions from all emissions units regulated by this permit comply with this facility-wide NO_x emissions cap. [PSD avoidance pursuant to 62-212.400(12), F.A.C.]

EXCESS EMISSIONS

19. 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 are prohibited. These emissions shall be included in the compliance averages for NO_x emissions. [Rule 62-210.700(4), F.A.C.]

20. Excess Emissions Allowed: Best operational practices shall be used to minimize hourly emissions that may

SECTION 3. EMISSIONS UNIT SPECIFIC CONDITIONS (FINAL)

A. Cogeneration Plant

occur during episodes of startup, shutdown and malfunction. Excess emissions resulting from startup, shutdown, and malfunction shall be permitted providing: (1) best operational practices to minimize emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration. For the combined cycle combustion turbine with a 30-day NO_x averaging period, this requirement shall mean the following. The 24-hour period shall be defined as the 24-hour block based on data collected from the NO_x CEMS. If the NO_x CEMS reports emissions in excess of the 30-day rolling average, the permittee may exclude up to two hours of excess emissions data caused by each startup, shutdown and malfunction during the 30-day period to determine compliance. No NO_x emission data shall be excluded from the annual NO_x emission caps. This requirement is not intended to limit the duration of a startup – only the amount of data that may be excluded from the 30-day compliance averaging period. If the 30-day rolling NO_x emissions rate exceeds the standard, the permittee shall notify the Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-210.700(1), F.A.C.]

STACK TESTING REQUIREMENTS

21. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7), F.A.C.]
22. Initial Compliance Stack Tests: Backup Steam Boiler No. 6 shall be tested to demonstrate initial compliance with the emissions standards within 60 days after achieving permitted capacity on natural gas but not later than 180 days after initial operation of the unit. The boiler shall be tested to demonstrate compliance with the fuel oil emissions standards within 180 days of exceeding 48 hours of fuel oil in a calendar year excluding periods of natural gas supply curtailment or interruption.
 - a. *Backup Steam Boiler No. 6*: Initial informational stack tests on the backup boilers No. 6 shall be conducted to establish the NO_x emissions rate for purposes of reporting the NO_x emission rate and complying with the facility-wide NO_x emission cap and other applicable NO_x emission limits. *{Permitting Note: The requirements in the original permit to conduct initial compliance tests on backup boiler No. 5 have previously been satisfied.}*

[Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

23. Annual Compliance Tests:
 - a. *Combined Cycle Combustion Turbine System*: During each federal fiscal year (October 1st to September 30th), the combined cycle combustion turbine system shall be tested to demonstrate compliance with the CO and visible emissions standards. Due to safety considerations, stack testing while firing the duct burner when there is no demand for steam would require dumping excess steam, which presents a safety issue given the existing configuration. Therefore, subsequent periodic testing for CO emissions may be with the duct burner on or off, as dictated by the system demand. Visible emissions for each backup steam boiler shall be conducted only if No. 2 fuel oil is fired for more than 400 hours during the federal fiscal year. *{Permitting Note: A safety evaluation of the steam vent system indicated that it did not meet code and was deemed unsafe; therefore, it was dismantled.}* [Rules 62-4.070(3) and 62-297.310(7), F.A.C.]
 - b. *New Backup Boiler No. 6*: During each federal fiscal year (October 1st to September 30th), the backup boiler No. 6 shall be tested to demonstrate compliance with the NO_x and visible emissions standards while firing natural gas. The boiler shall be tested to demonstrate compliance with the fuel oil emissions limits for SO₂, PM, NO_x and visible emissions during each calendar year when fuel oil firing exceeds 48 hours excluding periods of natural gas supply curtailment and interruptions. For determining compliance

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with the SO₂ emission limit, the use of 40 CFR Part 75 Appendix D is authorized. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; NSPS Subpart Dc and NESHAP 40 CFR 63, Subpart JJJJJ.]

24. **Special Compliance Tests:** When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rules 62-297.310(7), F.A.C.]
25. **Test Methods:** Any tests required by this permit 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	Method for Determining Particulate Matter Emissions
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 {Note: The method shall be based on a continuous sampling train.}
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.)
Part 75 Appendix D	Fuel Sulfur Analysis to determine SO ₂ Emissions.

The above methods are described in Appendix A of 40 CFR 60 and are 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. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

MONITORING REQUIREMENTS

26. **Continuous Emission Monitoring System:** The permittee shall calibrate, maintain and operate a CEMS in the stack to measure and record the emissions of NO_x from the combined cycle combustion turbine and duct burner system in a manner sufficient to demonstrate compliance with the NO_x emission limits and caps specified in this permit. The oxygen content or the carbon dioxide content of the flue gas shall also be monitored at the location where NO_x is monitored to correct the measured NO_x emissions rates to 15% oxygen and also reported as lb/hour. The NO_x CEMS shall be maintained in accordance with the monitoring equipment requirements in 40 CFR 75 for acid rain units. [Rule 62-4.070(3), F.A.C., NSPS Subpart GG in 40 CFR 60 and 40 CFR 75]
27. **Fuel Flow Monitoring:** The permittee shall install/maintain equipment to monitor the fuel flow rates of the combustion turbine, duct burner and backup steam boilers. [Rules 62-4.070(3) and 62-212.400(12), F.A.C. and NSPS Subpart GG in 40 CFR 60]

RECORDS AND REPORTS

28. **Fuel Consumption Rates Monthly Monitoring:** By the 15th calendar day of each month, the permittee shall record the monthly fuel consumption rates of the duct burner and backup steam boilers. The written log shall

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summarize the fuel consumption for the previous month of operation and the previous 12 months of operation. Information may be recorded and stored as an electronic file. Records shall be available for inspection and printing within at least three days of a request by the Department or Compliance Authority. [Rule 62-4.070(3), F.A.C.]

29. Annual Facility-Wide NO_x Emissions Report: To demonstrate compliance with the facility-wide annual NO_x emissions cap, the permittee shall calculate and record annual emissions as follows:

- a. Annual NO_x emissions from the combined cycle combustion turbine and duct burner system shall be determined by data collected from the NO_x CEMS.
- b. ***By April 1st of each year***, the permittee shall report the facility-wide annual NO_x emissions along with the Annual Operating Report. Annual NO_x emissions from the Backup Steam Boiler No. 5 shall be determined based on the annual fuel consumption rate and either the following NO_x emissions factors or more recent stack test data (at the option of the permittee).

No. 5 Steam Boiler: 0.110 lb NO_x/MMBtu (gas) and 0.1070 lb NO_x/MMBtu (oil).

Annual NO_x emissions from the Backup Steam Boiler No. 6 shall be determined based on the annual fuel consumption rate and the annual stack test data.

If the facility-wide annual NO_x emissions exceed the NO_x emissions cap, the permittee shall notify the Compliance Authority within three working days of discovery.

[Rules 62-4.070(3) and PSD avoidance pursuant to 62-212.400(12), F.A.C.]

30. Fuel Sulfur Records: The permittee shall maintain records of the fuel sulfur content of natural gas and No. 2 fuel oil fired. Such information may be provided by the natural gas pipeline vendor or the fuel oil vendor. The following methods shall be used to determine the sulfur content of natural gas: ASTM methods D4084-82, D3246-81, D5504, more recent versions of these methods, methods prescribed in Appendix D of 40 CFR 75, or other methods approved by the Department. The following methods shall be used to determine the sulfur content of fuel oil: ASTM D1552, ASTM D5453, ASTM D129-91, D2622-94 or D4294-90, more recent versions of these methods, methods prescribed in NSPS Subpart GG of 40 CFR 60 or other methods approved by the Department. The permittee may also have a sample of fuel analyzed to determine the actual sulfur content. Vendor certification acceptable in lieu of testing for fuel sulfur content. [NSPS Subparts Db and GG in 40 CFR 60, 40 CFR 75 and Rule 62-4.070(3), F.A.C.]
31. Stack Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the heat input rate of the emissions unit. [Rule 62-297.310(8), F.A.C.]
32. Semi-Annual NSPS Excess Emissions Reports: The permittee shall submit semi-annual excess emission reports in accordance with 40 CFR 60.7(d) to the Compliance Authority. [40 CFR 60.7]