City of Lakeland Electric
C. D. McIntosh, Jr. Power Plant
Facility ID No. 1050004
Polk County

Title V Air Operation Permit Revision

Permit No. 1050004-029-AV
(1st Revision of Title V Air Operation Permit No. 1050004-023-AV)

Permitting Authority
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Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Title V Section

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Title V Air Operation Permit Renewal
Permit No. 1050004-029-AV

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DRAFT/PROPOSED

PERMITTEE:
City of Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Permit No. 1050004-029-AV
C. D. McIntosh, Jr. Power Plant
Facility ID No. 1050004
Title V Air Operation Permit Revision

The purpose of this permit is to ~~renew the~~ revise Title V Air Operation Permit No. 1050004-023-AV for the above referenced facility in order to incorporate the terms and conditions of Air Construction Permit Nos. 1050004-019-AC and 1050004-026-AC, which authorized the construction of a selective catalytic reduction (SCR) system to reduce NO_X emissions and the installation of a sorbent injection system to reduce the emissions of sulfuric acid mist.

The existing C. D. McIntosh, Jr. Power Plant is located at 3030 East Lake Parker Drive, Lakeland, Polk County; UTM Coordinates: Zone 17, 409.0 km East and 3106.2 km North; Latitude: 28° 04' 50" North and Longitude: 81° 55' 32" West.

This 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.

1050004-023-AV Effective Date: January 1, 2009
1050004-029-AV Effective Date: *(Day 55)*
Renewal Application Due Date: May 20, 2013
Expiration Date: December 31, 2013

(Draft/Proposed)

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Trina Vielhauer, Acting Director
Division of Air Resource Management

TLV/jkh/adb

Subsection A. Facility Description.

This facility consists of three fossil fuel fired steam generators, two diesel powered generators, and two gas turbines. Fossil fuel fired steam generator Unit 1 is fired with natural gas, No. 6 fuel oil or on-specification used oil generated by the City of Lakeland. Fossil fuel fired steam generator Unit 2 is fired with natural gas, propane, No. 2 fuel oil or No. 6 fuel oil. Fossil fuel fired steam generator 3 is ~~primarily~~ fired with coal, refuse derived fuel, natural gas and petroleum coke. Gas Turbine Peaking Unit 1 is primarily fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. McIntosh Unit 5, a 370 MW combined cycle stationary combustion turbine, is fired with natural gas, or No. 2 or superior grade fuel oil with a maximum sulfur content of 0.05 percent by weight. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

E.U. ID No.	Brief Description
Regulated Emissions Units	
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3
-004	Gas Turbine Peaking Unit 1
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator
-028	McIntosh Unit 5 - 370 MW Combined Cycle Stationary Combustion Turbine
Unregulated Emissions Units and Activities	
-007	Tanks with greater than 10,000 gallon capacity installed prior to July 23, 1984
-008	Diesel drive coal tunnel sump engine
-009	Fire water UPS diesel No. 31
-010	Fire water UPS diesel No. 32
-011	CT startup diesel
-012	General purpose diesel engines
-013	Emergency generators
-014	General purpose painting
-015	Parts Cleaning
-016	Sand Blasting (Maintenance only)
-017	Wastewater Treatment Tank
-018	Three Cooling Towers (Units 2 and 3)
-019	Northside Waste Water Treatment Facility - Wastewater treatment processes and tanks
-020	Northside Waste Water Treatment Facility - Two emergency diesel generators
-021	Northside Waste Water Treatment Facility - Chemical and petroleum storage
-022	Northside Waste Water Treatment Facility - Miscellaneous activities

-023	Coal processing and conveying system
-024	Coal storage system
-025	Coal transfer and loading system
-026	Limestone handling and storage system
-027	Fly ash handling and storage system
-029	1.05 million gallon storage tank for McIntosh Unit 5, subject only to the reporting requirements of 40 CFR 60, Subpart Kb
-030	Mechanical Draft Cooling Tower

Subsection C. Applicable Regulations.

Based on the Title V Air Operation Permit Renewal application received on July 3, 2008, 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 important applicable regulations is shown in the following table.

Regulation	**E.U. ID No(s).**
Rule 62-210.300, F.A.C., Permits Required	-002, -003 & -004
Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-001
Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-005, -006
Acid Rain, Phase II SO_2	-001, -005, -006, -028
Acid Rain, Phase II NO_X	-006
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-001, -005, -006, -028
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-005, -006, -028
40 CFR 60, NSPS Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	-005, -006
40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	-028
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-006, -028
Compliance Assurance Monitoring (CAM)	-006

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

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

Emissions and Controls

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

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Containers shall be kept closed. [Rule 62-296.320(1)(a), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

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)1., F.A.C.]

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

a. maintenance of paved areas;
b. regular mowing of grass and care of vegetation; and,
c. limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

Annual Reports and Fees

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

FW6. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by May 1, 2009 and April 1st of each year, thereafter. [Rule 62-210.370(3), F.A.C.]

FW7. Annual Emissions Fee Form and Fee. The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download 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/permitting/tvfee.htm. [Rule 62-213.205, F.A.C.]

FW8. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V air operation permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

FW9. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.
d. Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to: Department of Community Affairs, Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9921, Fax: (850) 488-1739.
e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 1515, Lanham-Seabrook, MD 20703-1515, Telephone: (301) 429-5018.

Any required reports to be sent to the National Response Center, should be sent to: National Response Center, EPA Office of Solid Waste and Emergency Response, USEPA (5305 W), 401 M Street SW, Washington, D.C. 20460, Telephone: (800) 424-8802.
Send the required annual registration fee using approved forms made payable to: Cashier, Department of Community Affairs, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149
[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

FW10. Clean Air Interstate Rule (CAIR) Applicable Units. This facility contains emissions units that are subject to CAIR. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia recommended vacature of the Clean Air Interstate Rule. Because of this decision, the applicable CAIR requirements that were identified in the renewal application are not being included in the permit at this time. If, and at such time that, CAIR is ultimately upheld, you must begin complying with the CAIR program requirements contained in the renewal application and the Title V air operation permit must be revised accordingly. [Rules 62-213.440 and 62-296.470, F.A.C.]

Subsection A. Emissions Units -001

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

E.U. ID No.	Brief Description
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator

McIntosh Unit 1 is a forced draft boiler rated at a nominal load of 90 megawatts. The unit is fired with natural gas at a maximum heat input rate of 985 million Btu per hour (approximately 970 million cubic feet per hour), or No. 6 fuel oil, having a maximum sulfur content of 2.5 percent by weight, at a maximum heat input rate of 950 million Btu per hour (approximately 6,300 gallons per hour). This unit is also permitted to burn on-specification used oil generated by the City of Lakeland, at a maximum heat input rate of 950 million Btu per hour. McIntosh Unit 1 began commercial service in February, 1971. The stack parameters are: height, 150 feet: diameter, 9.0 feet; exit temperature, 277 degrees F; and, actual stack gas flow rate, 310,000 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
1	985	Natural Gas
	950	No. 6 Fuel Oil
	950	Used Oil

When a blend of fuel oil, on-specification used oil or natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate. [Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); and, 62-296.405, F.A.C.]

{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. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

A.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 Fuel Oil, On-Specification Used Oil, No. 2 Fuel Oil and combinations of natural gas, propane, No. 6 Fuel Oil, No. 2 Fuel Oil and/or On-Specification Used Oil. On-Specification used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures. [Rule 62-213.410, F.A.C.; and, 40 CFR 271.20(e)(3)]

A.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200 (Definitions - PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **A.5. - A.9.** are based on the specified averaging time of the applicable test method.

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rule 62-296.405(1)(a), F.A.C.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-210.700(3), F.A.C.]

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1)(b), F.A.C.]

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1) (c)1.j., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. The No. 6 fuel oil sulfur content shall not exceed 2.5 percent, by weight. [Rule 62-296.405(1)(e)3., F.A.C.]

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.11. Excess Emissions Allowed - Malfunctions. Excess emissions resulting from 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. [Rule 62-210.700(1), F.A.C.]

A.12. Excess Emissions Allowed - Startup And 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.13. Excess Emissions Prohibited. 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(4), F.A.C.]

Monitoring of Operations

A.14. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery.** 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.]

Test Methods and Procedures

A.15. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Method 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.)
DEP Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

A.16. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE) and particulate matter (PM) emissions. [Rule 62-297.310(7), F.A.C.]

A.17. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE and PM. [Rule 62-297.310(7)(a)3., F.A.C.]

A.18. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.19. 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 62-297.520, F.A.C. [Rule 62-296.405(1)(e)1., F.A.C.]

A.20. 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.

[Rule 62-297.401, F.A.C.]

A.21. 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 filter temperature 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 62-296.405(1)(e)2. and 62-297.401, F.A.C.]

A.22. 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 by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery.** [Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]

A.23. Sulfur Content Sampling Methods. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.24. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

A.25. PM Testing Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

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

A.26. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions	Every 3 months (quarter)	**A.28.**

[Rule 62-296.405(1)(g), F.A.C.]

A.27. Reporting of Excess Emissions Due to Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program 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 or the appropriate Local Program. [Rule 62-210.700(6), F.A.C.]

A.28. Quarterly Excess Emissions Report. Submit to the Department a written report of emissions in excess of emission limiting standards 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 and 62-296.405(1)(g), F.A.C.]

Other Requirements

A.29. On-Specification Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:
a. *On-Specification Used Oil Emissions Limitations.* This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 parts per million (ppm). On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. *Quantity Limitation.* This emissions unit is permitted to burn on-specification used oil that is generated by the City of Lakeland in the production and distribution of electricity, not to exceed 42,000 gallons (1,000 barrels) during any calendar year.

c. *PCB Limitation.* 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. *Operational Requirements.* 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 Requirements.* For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

(1) Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications. [40 CFR 279.72(a)]

(2) Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(a) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(b) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(c) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs.

[40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.

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).

f. *Recordkeeping Requirements.* 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 placed into inventory to be burned and the gallons of on-specification used oil burned each month.

(2) Results of the analyses of each deposit of used oil, as required by the above conditions.

(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. *Reporting Requirements.* The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into

inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year.
[Rule 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

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

E.U. ID No.	Brief Description
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3

Diesel Engine Peaking Units 2 and 3 are diesel fired internal combustion engines, which each drives a generator capable of producing electric power at a maximum rating of 2.5 megawatts. These units are each fired on No. 2 fuel oil, with a maximum sulfur content of 0.5 percent by weight, at a maximum firing rate of 201.6 gallons per hour. This corresponds to a maximum heat input of 28 million Btu per hour. Each diesel engine peaking unit has its own stack. The stack parameters are: height, 20 feet: diameter, 2.6 feet; exit temperature, 715 degrees F; and, actual stack gas flow rate, 24,529 acfm. Diesel Engine Peaking Units 2 and 3 began commercial service in 1970.

{Permitting note(s): The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity.
a. The maximum heat input rate of each diesel engine peaking unit is 28 million Btu per hour
b. **Not federally enforceable.** The maximum firing rate of each diesel engine peaking unit is 201.6 gallons per hour firing No. 2 fuel oil.
[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{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. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels. Only distillate (No. 2) fuel oil shall be fired in the diesel engine peaking units. [Rule 62-213.410, F.A.C.]

B.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition **B.5**. is based on the specified averaging time of the applicable test method.

B.5. Visible Emissions. Visible emissions from each diesel engine peaking unit shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]

B.6. **Not federally enforceable.** Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight. [Rule 62-213.440, F.A.C. and Applicant request.]

Excess Emissions

B.7. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or 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. [Rule 62-210.700(1), F.A.C.]

B.8. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in the most recent Title V air operation permit application. [Rule 62-210.700(1), F.A.C. and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

B.9. Excess Emissions Prohibited. 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(4), F.A.C.]

Monitoring of Operations

B.10. Fuel Sulfur Monitoring. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

B.11. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

B.12. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE). [Rule 62-297.310(7), F.A.C.]

B.13. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutant: VE. [Rule 62-297.310(7)(a)3., F.A.C.]

B.14. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

B.15. VE Tests Method. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

B.16. Sulfur Content Sampling Methods. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440 and 62-297.440, F.A.C.]

B.17. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

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

Subsection C. Emissions Unit -004

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

E.U. ID No.	Brief Description
-004	Gas Turbine Peaking Unit 1

Gas Turbine Peaking Unit 1 consists of a gas turbine, which drives a generator producing electrical power at a nominal nameplate rating of 20 megawatts. The gas turbine is fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. The maximum fuel firing rate is 320 million cubic feet per hour of natural gas (approximately 330 million Btu per hour) or 2,310 gallons per hour of No. 2 fuel oil (approximately 320 million Btu per hour). Gas Turbine Peaking Unit 1 began commercial service in 1973. The stack parameters are: height, 35 feet: diameter (rectangular), 13'2" x 10'11" feet; exit temperature, 900 degrees F; actual stack gas flow rate (gas), 742,174 acfm: and, actual stack gas flow rate (oil), 682,334 acfm.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This unit is not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity.

a. The maximum heat input rate of the turbine is 330 million Btu per hour (lower heating value) at 30 degrees F while firing natural gas and 320 million Btu per hour (lower heating value) at 30 degrees F while firing No. 2 fuel oil.

b. **Not federally enforceable.** The maximum firing rate of the turbine is 320 million cubic feet per hour when firing natural gas or 2,310 gallons per hour when firing No. 2 fuel oil.

[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

C.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation - Fuels. Only natural gas or distillate (No. 2) fuel oil shall be fired in the combustion turbine. [Rule 62-213.410, F.A.C.]

C.4. Hours of Operation. These emissions unit(s) may operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition **C.5.** is based on the specified averaging time of the applicable test method.

C.5. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]

C.6. **Not federally enforceable.** Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight. [Rule 62-213.440, F.A.C. and Applicant request.]

Excess Emissions

C.7. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that 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. [Rule 62-210.700(1), F.A.C.]

C.8. Excess Emissions Prohibited. 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(4), F.A.C.]

Monitoring of Operations

C.9. Fuel Sulfur Monitoring. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

C.10. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

C.11. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE). [Rule 62-297.310(7), F.A.C.]

C.12. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE. [Rule 62-297.310(7)(a)3., F.A.C.]

C.13. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

C.14. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

C.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440 and 62-297.440, F.A.C.]

C.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:
a. only gaseous fuels; or
b. gaseous fuels in combination with any amount of liquid fuels for less than 400 hours per year; or
c. only liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

Subsection D. Emissions Unit -005

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

E.U. ID No.	Brief Description
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator

McIntosh Unit 2 is a nominal 114.7 megawatt (electric) fossil fuel fired steam generator. The unit is fired on low sulfur No. 6 or No. 2 fuel oil with a maximum heat input of 1,115 million Btu per hour, or natural gas with a maximum heat input of 1,184.5 million Btu per hour. The stack parameters are: height, 157 feet: diameter, 10.5 feet; exit temperature, 277 degrees F; and, actual stack gas flow rate, 380,200 acfm. McIntosh Unit 2 began commercial service in June, 1976.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(8)1., F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
2	1,184.5	Natural Gas
	1,115	No. 6 Fuel Oil
	1,115	No. 2 Fuel Oil

When a blend of fuel oil and natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEM will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{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. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

D.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation. Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 fuel oil, No. 2 fuel oil and combinations of natural gas, propane, No. 6 fuel oil and/or No. 2 fuel oil. [Rule 62-213.410, F.A.C.]

D.4. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **D.5. - D.6.**; and, **D.8. - D.9.** are based on the specified averaging time of the applicable test method.

D.5. Particulate Matter. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu). [40 CFR 60.42(a)(1)]

D.6. Visible Emissions. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42(a)(2)]

D.7. Sulfur Dioxide. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel. [40 CFR 60.43(a)(1)]

D.8. Sulfur Dioxide. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [40 CFR 60.43(c)]

D.9. Nitrogen Oxides. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

a. 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
b. 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel.

[40 CFR 60.44(a)(1) & (2)]

D.9. Nitrogen Oxides. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

[40 CFR 60.44(b)]

Excess Emissions

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

D.10. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that 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. [Rule 62-210.700(1), F.A.C.]

D.11. Excess Emissions Prohibited. 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(4), F.A.C.]

Continuous Monitoring Requirements

D.12. Sulfur Dioxide. For a fossil fuel fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d). **The applicant has elected to utilize fuel sampling and analysis in lieu of a continuous monitoring system for sulfur dioxide.** [40 CFR 60.45(b)(2) and Applicant request.]

Test Methods and Procedures

D.13. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B, or 6C	Methods for Determining Sulfur Dioxide Emissions
Method 7, Method 7A, 7C, 7D, or 7E	Determination of Nitrogen Oxide Emissions
EPA Method 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.)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

D.14. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for particulate matter, nitrogen oxides, ~~sulfur dioxide,~~ and visible emissions. The NO_X ~~and SO_2~~ RATA test data may be used to demonstrate compliance with the annual test

requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

D.15. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

D.16. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

D.17. SO_2 Compliance. Compliance with the sulfur dioxide emission standard of specific condition **D.7.** shall be demonstrated using the fuel sampling and analysis procedures of specific condition **D.18.** [Rule 62-213.440, F.A.C. and Applicant request]

D.18. Fuel Sampling. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard and as the substitute for the sulfur dioxide continuous monitoring system:

a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s), to analyze a representative sample of the blended fuel following each fuel delivery, (2) for gaseous fuels using ASTM D1072-90, or the respective successor ASTM method.
b. Record daily the amount of each fuel fired, the density of each fuel, and the percent sulfur content by weight of each fuel.
c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rule 62-213.440, F.A.C.]

D.19. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

D.20. PM Testing Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Recordkeeping and Reporting Requirements

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

D.21. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)

NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**D.23.**
Quarterly Excess Emissions	Every 3 months (quarter)	**D.22.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

D.22. Quarterly Excess Emissions Report. Submit to the Department a written report of emissions in excess of emission limiting standards 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. [Rule 62-210.700(6), F.A.C.]

Miscellaneous Requirements

D.23. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

D.24. NSPS Requirements - Subpart D. Except as otherwise provided in this permit, this fossil-fuel fired steam generator shall comply with all applicable provisions of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted by reference in Rule 62-204.800(8)(b)1., F.A.C. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart D** included with this permit. [Rule 62-204.800(8)(b)1., F.A.C.]

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

E.U. ID No.	Brief Description
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator

McIntosh Unit 3 is a nominal 364 megawatt (electric) dry bottom wall-fired fossil fuel fired steam generator. The unit is fired on coal, residual oil, natural gas and co-fires refuse derived fuel (RDF) and petroleum coke. The maximum heat input rate is 3,640 million Btu per hour. Unit 3 is equipped with an electrostatic precipitator (ESP), a flue gas desulfurization system (FGD), and low NO_X burners (LNB) and an overfire air (OFA) system to control emissions. McIntosh Unit 3 began commercial service in September, 1982. Compliance Assurance Monitoring (CAM) requirements for the ESP are included in Appendix CAM. The FGD is exempted from CAM because the Acid Rain SO_2 continuous emissions monitor will be used to demonstrate continuous compliance. The stack parameters are: height, 250 feet: diameter, 18 feet; exit temperature, 125 degrees F; and, actual stack gas flow rate, 1,260,536 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(8)(b)1., F.A.C.; Rule 212.400(6), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination; Compliance Assurance Monitoring (CAM), adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).

Essential Potential to Emit (PTE) Parameters

E.1. Capacity. The maximum heat input rate is 3,640 MMBtu per hour. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate. [Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{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. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

E.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

E.3. Methods of Operation - Fuels. The only fuels allowed to be burned are:

a. Coal only;
b. Low sulfur fuel oil only (≤ 0.5 percent sulfur by weight);

c. Coal and up to 10 percent refuse (based on heat input);
d. Low sulfur fuel oil and up to 10 percent refuse (based on heat input);
e. Coal and up to 20 percent petroleum coke (based on weight);
f. Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input);
g. High sulfur fuel oil (> 0.5 percent sulfur by weight); and,
h. Natural gas or propane only, or in combination with any of the other fuels or fuel combinations listed above.

[Rules 62-4.160(2), 62-210.200 (Definitions - PTE), and 62-213.440(1), F.A.C.; and, PSD-FL-008(B)]

E.4. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **E.5.-E.7.; E.9.-E.11.;** and, **E.13.-E.14.** are based on the specified averaging time of the applicable test method.

E.5. Particulate Matter. Particulate matter emitted to the atmosphere from the boiler shall not exceed:

Mode of Firing	Pound / MMBtu Heat Input
Coal	0.044
Coal/Petroleum Coke	0.044
Coal/Refuse	0.050
Coal/Petroleum Coke/Refuse	0.050
Oil	0.070
Oil/Refuse	0.075

[40 CFR 60.42(a)(2); and, PSD-FL-008(B)]

E.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42(a)(2); and, PSD-FL-008(B)]

E.7. Sulfur Dioxide. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of: (1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue, or (2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in 40 CFR 60.43(e). [40 CFR 60.43(a)(1) and (2)]

E.8. Sulfur Dioxide. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$PS_{SO2} = [y(340) + z(520)]/(y+z)$

where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.
[40 CFR 60.43(b)]

Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [40 CFR 60.43(c)]

E.9. Sulfur Dioxide. A flue gas desulfurization system will be installed to treat exhaust gases and will operate such that whenever coal or blends of coal and petroleum coke or refuse are burned, sulfur dioxide gases discharged to the atmosphere from the boiler shall not exceed 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction) when emissions are less than 0.75 pound per million Btu heat input. Compliance with the percent reduction requirement shall be determined on a 30-day rolling average. This compliance information shall be retained for a period of five years and made available by the City upon request of the Department. Whenever blends of petroleum coke with other fuels are co-fired, sulfur dioxide emissions shall not exceed 0.718 pound per million Btu heat input based on a 30-day rolling average and shall comply with the reduction requirements given above. [PSD-FL-008(B); and, Rule 62-213.440, F.A.C.]

E.10. Sulfur Dioxide. The burning of high sulfur oil (greater than 0.5 percent sulfur by weight) or a combination of high sulfur oil and municipal refuse as an emergency fuel without the use of the SO_2 scrubber will be allowed only when the flue gas desulfurization system malfunctions to the extent that the burning of coal would cause emission limitations to be exceeded. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition. [PSD-FL-008(B)]

E.11. Sulfur Dioxide. During malfunctions of equipment which cause an interruption of the coal feed to the boiler, the burning of high sulfur oil (greater than 0.5 percent sulfur by weight) or a combination of high sulfur oil and municipal refuse will be allowed only if all flue gases are fully scrubbed by the SO_2 scrubber. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition. [PSD-FL-008(B)]

E.12. Sulfur Dioxide. Continuous burning of natural gas, low sulfur fuel oil (less than or equal to 0.5 percent sulfur by weight), or combinations of these two fuels with or without the use of the SO_2 scrubber will be allowed. [PSD-FL-008(B)]

E.13. Nitrogen Oxides. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

a. 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
b. 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
c. 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

[40 CFR 60.44(a)(1), (2) & (3)]

E.14. Nitrogen Oxides. Except as provided under paragraphs 40 CFR 60.44(c) and (d), when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).
[40 CFR 60.44(b)]

~~**E.15.** Carbon Monoxide (CO).~~
~~a. Emissions of CO shall not exceed 0.20 lb/mmBtu heat input on a 30-operating day rolling average as demonstrated by the required CEMS. This CO emission limit may be adjusted downward to make this limit more stringent based on the Department's reassessment of BACT during the subsequent phase of this project involving installation of selective catalytic reduction.~~
~~b. Emissions of CO shall not exceed 0.20 lb/mmBtu on a 3-hr average during the initial compliance demonstration.~~
~~[Rules 62-210.200(BACT) and 62-212.400(PSD), F.A.C.; and, PSD-FL-387.]~~

~~**E.16.** Emissions Limits Subject to Revision. Emissions of CO from Unit 3 shall not exceed the limitations specified in this permit. Based on results of compliance tests and continuous monitoring data, the Department will reassess the BACT determination in conjunction with the subsequent phase of the project which will include installation of selective catalytic reduction. The emission limit may be adjusted downward to make this limit more stringent provided that overall control attained for all air pollutants including CO, SO_2, NO_X, PM/PM_{10}, sulfuric acid mist and VOC is optimized. Such revision shall be based on data that represents a full range of operating conditions and a representative period of time. Such revision, if required by the Department, shall be in the form of a federally enforceable permit and shall be publicly noticed by the permittee. [Rules 62-4.070(3), 62-210.200(BACT) and 62-212.400(PSD), and 62-212.400(7)(a), F.A.C.; and, and, PSD-FL-387.]~~

E.15. Ammonia Emissions (Slip). Subject to the requirements of Condition 36 in this section, the SCR system shall be operated for an ammonia slip target of less than 5 ppmv based on the average of three, 1-hour test runs. [Air Construction Permit No. 1050004-026-AC, Specific Condition 12.]

E.16. CO Emission Limit Subject to Revision. Emissions of carbon monoxide (CO) from Unit 3 shall not exceed 0.20 pounds per million Btu heat input (lb/MMBtu) on a 30-day rolling average as described in air construction permit 1050004-018-AC. Based on results of compliance tests and analysis of 12 months worth of continuous monitoring data, the Department will reassess the previously issued best available control technology (BACT) determination. The emission limit may be adjusted downward to make this limit more stringent provided that overall control attained for all air pollutants including CO, SO_2, NO_X, PM/PM_{10}, sulfuric acid mist, and VOC is optimized. Such revision shall be based on data that represents a full range of operating conditions and a representative period of time. Such revision, if required by the Department, shall be in the form of an air construction permit following the Department's procedures in Rules 62-210.300 and 62-4.055, F.A.C. [Air Construction Permit Nos. 1050004-019-AC, Specific Condition 13.a and 1050004-026-AC, Specific Condition 13.]

E.17. NOx Emission Limit. NOx emissions from Unit 3 shall not exceed 0.22 lb/MMBtu of heat input based on a calendar year average of all periods of operation, including startup, shutdown and malfunction. The permittee shall begin collecting and averaging data towards a demonstration of compliance with the new NOx emissions limitation beginning January 1, 2011. [Air Construction Permit No. 1050004-026-AC, Specific Condition 13.b.]

Excess Emissions

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

E.1~~7~~8. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that 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. [Rule 62-210.700(1), F.A.C.]

E.1~~8~~9. Excess Emissions Prohibited. 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(4), F.A.C.]

Monitoring of Operations

E.~~19~~20. CAM Plan. This emissions unit is subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM for the controlled emissions of particulate matter. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C. [40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

E.2~~0~~1. Use of SO_2 CEMS For Continuous Compliance. Pursuant to 40 CFR 64.2(b)(1)(vi), the applicant has elected to use the existing certified Acid Rain SO_2 continuous emissions monitor for continuous compliance in order to be exempted from the Compliance Assurance Monitoring (CAM) requirements contained in 40 CFR 64. [40 CFR 64.2(b)(vi); and, Applicant request]

Continuous Monitoring Requirements

E.2~~1~~2. Performance Specifications and Quality Assurance. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 180 calendar days of commencing operation following installation of the Low-NO_X burners and overfire air system. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests 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 expected range of emissions and corresponding emission standards. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.; and, PSD-FL-387.]

E.2~~2~~3. CEMS Data Requirements for CO BACT Standard.

a. *Data Collection*. The CO CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All

data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments.

b. *Operating Hours and Operating Days*. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. *Valid Hourly Averages*. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
   (1) Hours that are not operating hours are not valid hours.
   (2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

d. *Rolling 30-day average.* Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

e. *Monitor Availability*. The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required 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.

[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.; and, PSD-FL-387.]

E.2~~3~~4. CEM Requirements. Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. In addition, an ASTM-certified automatic solid fossil fuel sampler shall be installed which produces a representative daily sample for analysis of sulfur, moisture, heating value and ash. The solid fossil fuel data shall be used in conjunction with emissions factors and the continuous monitoring data to calculate SO_2 reduction. [PSD-FL-008(B)]

E.2~~4~~5. CEMS Annual Emissions Requirement. The owner or operator shall use data from the CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200, and 62-210.370(3), F.A.C.; and, PSD-FL-387.]

E.26. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate, and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. [Air Construction Permit No. 1050004-019-AC, Specific Condition 22.]

Test Methods and Procedures

E.2~~5~~7. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B or 5F	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B or 6C	Methods for Determining Sulfur Dioxide Emissions
Method 7, Method 7A, 7C, 7D or 7E	Determination of Nitrogen Oxide Emissions
10	Determination of Carbon Monoxide Emissions
EPA Method 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.)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

E.2~~6~~8. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and visible emissions (VE). The NO_X and SO_2 RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

E.2~~7~~9. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

E.~~28~~30. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

E.~~29~~31. Continuous Compliance with CO limits. Compliance with the 30 operating day rolling average shall be demonstrated using data collected from the required CEMS. [Rule 62-4.070(3), F.A.C.; and, PSD-FL-387.]

E.3~~0~~2. VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

E.3~~1~~3. PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or

c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

E.34. Determining Actual SAM Emissions. The permittee must demonstrate on an annual basis, for a period of 5 years from the date of the maximum sulfur content tested, that SAM emissions increases as a result of this project are less than 7 TPY. The permittee shall operate the sorbent injection system at a frequency and injection rate for SAM control to satisfy this requirement. An automated control system will be used to adjust the sorbent flow rate for the given set of operating conditions based on the most recent performance test results. Actual SAM emissions shall be calculated using the information available for the given operating conditions (e.g., the sulfur content of fuel blend, the SO_2 emission rate prior to the SCR catalyst, the unit load, the flue gas flow rate, the sorbent injection rate and the current catalyst oxidation rate). If performance testing shows that it is unnecessary to operate the sorbent injection system for a given coal blend or the sorbent injection system is removed, the permittee shall determine actual SAM emissions based on emissions factors developed through the performance tests. [Air Construction Permit No. 1050004-026-AC, Specific Condition 16 and Rule 62-212.300(1)(e), F.A.C.]

E.35. SAM Performance Tests and Sorbent Injection for SAM Emissions Control. The permittee conducted stack tests to determine the uncontrolled sulfuric acid mist emission rate, the controlled sulfuric acid mist emission rate, and actual control efficiency of the installed sorbent injection system. Tests were conducted while firing the fuel blend with the highest sulfur content that will be fired in the unit. During each test run, the permittee continuously monitored and recorded the sorbent injection rate. The purpose of these tests were to determine actual control efficiency of the installed systems and to establish the correlation between SAM emissions and the sorbent injection rate, which will be used to calculate the actual annual emissions. If the permittee desires to alter the injection rate of the system that has been previously determined (due to lower sulfur coal being burned, to turn off the system, or any other situation the permittee feels the system can be adjusted for), then the following tests shall be conducted. Within 45 days of firing a fuel blend with a sulfur content that is 0.20% sulfur by weight (based on a 14-operational day rolling average) higher than the maximum sulfur content previously tested or if the permittee desires a new injection rate, then the permittee shall conduct the following additional SAM performance tests.

a. Conduct the SAM performance tests in accordance with the following requirements, or
   (1) For each set of operating conditions being evaluated, the permittee shall conduct at least a 1-hour test run to determine SAM emissions. At least nine such test runs shall be conducted to evaluate the effect on SAM emissions from such parameters as the SO_2 emission rate prior to the SCR catalyst (and FGD system), the unit load, the flue gas flow rate, the sorbent injection rate and the current catalyst oxidation rate.
   (2) Tests shall be conducted under a variety of fuel blends and load rates that are representative of the actual operating conditions. Sufficient tests shall be conducted to establish the SAM emissions rates for the following scenarios: SCR reactor in service (ammonia injection) without sorbent injection, and SCR reactor in service (ammonia injection) under varying operating conditions and levels of sorbent injection.
   (3) At least 15 days prior to initiating the performance tests, the permittee shall submit a test notification, preliminary test schedule and test protocol to the Bureau of Air Regulation and the Compliance Authority.
   (4) Within 45 days following the last test run conducted, the permittee shall provide a report summarizing the emissions tests and results. All SAM emissions test data shall be provided with this report.
   (5) Within 45 days following the submittal of the emissions test report and no later than 90 days following the last test run conducted, the permittee shall submit a project report summarizing the following:

(a) Identify each set of operating conditions evaluated;
(b) Identify each operating parameter evaluated;
(c) Identify the relative influence of each operating parameter, describe how the automated control system will adjust the sorbent injection rate based on the selected parameters;
(d) Identify the frequency with which operational parameters will be reevaluated and adjusted within the automated control system;
(e) Provide the algorithm used for the automated control system or a series of related performance curves; and
(f) Provide details for calculating and estimating the SAM emissions rate based on the level of sorbent injection and operating conditions. The test results shall be used to adjust the sorbent injection control system and estimate SAM emissions.

b. If the sorbent injection system is removed or is determined to be unnecessary for a given coal blend, conduct at least three, 1-hour test runs at permitted capacity to determine the SAM emissions rate.

The permittee shall use the data collected to calculate the actual SAM emissions when operating under the given conditions, including the period of time from first fire of the fuel blend until the performance test results are known. [Air Construction Permit No. 1050004-026-AC, Specific Condition 15.]

E.36. Ammonia Slip Tests. Annual compliance with the ammonia (NH_3) slip target shall be determined using EPA conditional test method (CTM-027), EPA method 320, or other methods approved by the Department. If the tested ammonia slip rate exceeds 5 ppmv during the test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;
b. Before the ammonia slip exceeds 7 ppmv, take corrective actions that result in lowering the ammonia slip to less than 5 ppmv; and
c. Test and demonstrate that the ammonia slip is less than 5 ppmv within 30 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 less than 5 ppmv, testing and reporting shall resume on an annual basis. [Air Construction Permit No. 1050004-026-AC, Specific Condition 18.]

Recordkeeping and Reporting Requirements

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

E.3~~2~~7. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**E.37. & E.39.**
Quarterly Excess Emissions	Every 3 months (quarter)	**E.33., E.34., E.35.**
Monthly CO CEMS		**E.36.**

{Note: If there are no periods of excess emissions as defined in 40 CFR 60 Subpart D, a statement to that effect may be submitted with the SIP Quarterly Excess Report to suffice for the NSPS Report.}
[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

E.3~~3~~8. Excess Emissions Reports - Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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. [Rule 62-210.700(6), F.A.C.]

E.3~~4~~9. Quarterly Excess Emissions Reports. Submit to the Department a written report of emissions in excess of emission limiting standards 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. [Rule 62-210.700(6), F.A.C.]

E.~~35~~40. Excess Emissions Reporting- *SIP Quarterly Report*. Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standard following the NSPS format in 40 CFR 60.7(c), Subpart A. In addition, the report shall summarize the CO CEMS system monitor availability for the previous quarter. [Rules 62-4.130, 62-210.700(6) and 62-212.400(BACT), F.A.C.]

E.~~36~~41. Monthly CO CEMS Report. The permittee shall submit, on a monthly basis, a report in electronic file format which includes Unit 3 CO, NO_X, and heat input data. The report shall be submitted by the 15th of each month by mailing a compact disc to the Department's Bureau of Air Regulation Title V Permitting Section and shall include all hourly readings from the previous month. Alternatively, upon contacting the Bureau's project engineer, the file may be emailed to the appropriate BAR personnel. [Rule 62-4.070(3), F.A.C.; and, PSD-FL-387.]

E.~~37~~42. Excess Emissions Report. In addition to the requirements of 40 CFR 60.7, each excess emissions report shall include the periods of oil consumption due to flue gas desulfurization system malfunction. [PSD-FL-008]

Miscellaneous Requirements

~~**E.38.** Reporting of Future Increases. The City shall maintain and submit to the Department on an annual basis for a period of five years from the date that the unit is initially co-fired with petroleum coke, information demonstrating in accordance with 40 CFR 52.21(b)(33) and 40 CFR 52.21(b)(21)(v) that the operational changes did not result in emissions increases of carbon monoxide, nitrogen oxides, or sulfuric acid mist. [PSD-FL-008(B)]~~

E.~~39~~43. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

E.4~~0~~4. NSPS Requirements - Subpart D. Except as otherwise provided in this permit, this fossil-fuel fired steam generator shall comply with all applicable provisions of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted

by reference in Rule 62-204.800(8)(b)1., F.A.C. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart D** included with this permit. [Rule 62-204.800(8)(b)1., F.A.C.]

E.45. Future Actual Emissions Reporting. The permittee shall maintain and submit to the Department on an annual basis for a period of 5 years from the date the SCR systems are initially operated, information demonstrating in accordance with Rule 62-212.300(1)(e), F.A.C., using the emissions computation and reporting procedures in Rule 62-210.370, F.A.C., that the installation of LNB, OFA and SCR did not result in an emissions increase of PM or SAM that would equal or exceed the respective significant emission rates as defined in Rule 62-210.300, F.A.C. The future emissions shall be compared with the baseline actual emissions for the period 2002-2001 for SAM and 2003-2002 for PM as reported in the annual operating reports (AOR) using EPA Method 5B for PM and Method 8A (controlled condensate) for SAM. [Air Construction Permit No. 1050004-019-AC, Specific Condition 14.]

E.46. New Control Equipment. In accordance with Rule 62-210.300(1)(a), F.A.C., if the sorbent injection system is removed, the permittee shall obtain an air construction permit to install new acid mist mitigation equipment or to reinstall the sorbent injection system if required to maintain SAM emissions below a 7 TPY increase above the baseline emissions, which were estimated at 136 TPY. [Air Construction Permit No. 1050004-026-AC]

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

E.U. ID No.	Brief Description
-028	McIntosh Unit 5 - 370 MW Combined Cycle Stationary Combustion Turbine

McIntosh Unit 5 is a Westinghouse 501G combustion turbine operating in combined cycle with a HRSG and 120 MW steam electric turbine. The turbine is fired with natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil. NO_X emissions are controlled by low NO_X burners, water injection and a selective catalytic reduction (SCR) system. An oxidation catalyst was installed to control carbon monoxide (CO) and volatile organic compound (VOC) emissions in 2003. The stack parameters are: height, 300 feet; diameter, 20 feet; exit temperature, 187 degrees F; actual stack gas flow rate (gas), 1,271,428 acfm; and, actual stack gas flow rate (oil), 1,291,502 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8)(b), F.A.C.; Rule 62-212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated July 10, 1998; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR). Simple cycle combustion turbine operation began in March, 2000. Combined cycle combustion turbine operation began in January, 2002.}

Essential Potential to Emit (PTE) Parameters

F.1. Permitted Capacity. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,407 million Btu per hour when firing natural gas, nor 2,236 million Btu per hour when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves approved by the Department, attached in **Appendix W501G McIntosh #5, Lakeland FL - Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01)**, for the heat input correction to other temperatures may be utilized to establish heat input rates over a range of temperatures for compliance determination. Monitoring required under 40 CFR 60.334(a) shall satisfy periodic monitoring requirements for heat input. [Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); and 62-213.440(1)(b)1.b., F.A.C.; and, PSD-FL-245C.]

F.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

F.3. Methods of Operation - Fuels. Only pipeline natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Rules 62-212.400, 62-212.410, and 62-213.410, F.A.C.; and, PSD-FL-245.]

F.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; and, PSD-FL-245.]

F.5. Fuel Usage as Heat Input - Fuel Oil. Fuel usage as heat input shall not exceed 599 x 10^9 Btu (LHV) per year (rolled monthly). [PSD-FL-245.]

Control Technology

F.6. Selective Catalytic Reduction. The permittee shall operate SCR equipment and operate an oxidation catalyst. The oxidation catalyst shall be designed for a minimum 90% destruction efficiency at base load. [PSD Permit Modification dated October 8, 2002, specific condition 17.]

F.7. Water Injection for Oil Firing. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [PSD-FL-245.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **F.9.-F.13.** are based on the specified averaging time of the applicable test method.

F.8. Summary of Emission Standards & Limits and Performance Criteria. The following table is a summary of the BACT determination and is followed by the applicable specific conditions **F.9.** through **F.13.** Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Combined	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	Oxidation Catalyst (annual test 2 ppm criteria at full load firing natural gas.)	Oxidation Catalyst	10	Conventional SCR with Oxidation Catalyst. Clean fuels, good combustion.

[PSD Permit Modification dated October 8, 2002, specific condition 20.]

F.9. Nitrogen Oxides. NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 pounds per hour (when firing natural gas) and 148 pounds per hour (when firing fuel oil) to be demonstrated by stack tests. [PSD-FL-245.]

F.10. Carbon Monoxide Performance Criteria. The concentration of CO in the exhaust gas shall be additionally controlled by the use of an oxidation catalyst with a minimum of 90% CO removal efficiency (based upon design at base load). The CO emissions shall be tested annually at full load and shall not exceed 2 ppmvd when firing natural gas as measured by EPA Method 10. The oxidation catalyst shall be maintained according to manufacturer's recommendations, however in the event that CO emissions exceed 2 ppmvd (as demonstrated by annual testing above) the permittee shall implement a remedy and re-test within 90 days of operation. Should the re-test result in CO emissions exceeding 2 ppmvd, the remedy shall be to completely replace the oxidation catalyst. [PSD Permit Modification dated October 8, 2002, specific condition 22.]

F.11. Sulfur Dioxide. SO_2 emissions (at ISO conditions) shall not exceed 8 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade distillate fuel oil, as measured by applicable compliance methods. Emissions of SO_2 shall not exceed 38.4 tons per year. [PSD-FL-245C and Applicant request to Escape PSD Review.]

F.12. Visible Emissions. Visible emissions shall not exceed 10 percent opacity. [PSD-FL-245.]

F.13. Volatile Organic Compounds. VOC emissions shall be additionally controlled through the use of an oxidation catalyst. CO emissions shall be employed as a surrogate for VOC emissions and no further annual testing will be required. [PSD Permit Modification dated October 8, 2002, specific condition 25.]

Excess Emissions

The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.

F.14. Excess Emissions Allowed. Excess emissions from this emissions unit resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24 hour period for cold startup or two hours in any 24 hour period for other reasons unless specifically authorized by the Department for longer duration. During any calendar day in which a start-up, shutdown, or fuel change occurs, the following alternative NO_X limit applies:

a. 100 lbs/hr on the basis of a 24-hour average
b. 200 lbs/hr on the basis of a 24-hour average if fuel oil is fired during a start-up or shut-down within the 24-hour period.

[Rule 62-210.700(1), F.A.C.; and, PSD Permit Modification dated October 8, 2002, specific condition 26.]

F.15. Excess Emissions Prohibited. 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(4), F.A.C.]

Monitoring of Operations

F.16. Fuel Oil Monitoring Schedule. The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the C. D. McIntosh, Jr. Power Plant, an analysis which reports the sulfur content and the nitrogen content of the fuel shall be provided by the vendor. The analysis shall also specify the methods by which the analysis was conducted and shall comply with the requirements of 40 CFR 60.335(d). [PSD-FL-245.]

F.17. Natural Gas Monitoring Schedule. The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2):

a. Monitoring of natural gas nitrogen content shall not be required.
b. Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. Monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
c. Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the custom fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
d. The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than one grain per 100 cubic feet of natural gas) shall be considered as a change in the natural gas supply. Sulfur

content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

e. Records of sampling analyses and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.

f. The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission or Gulfstream) provided the approved test methods are used.

[PSD-FL-245.]

{Permitting note: The permittee may satisfy this custom monitoring schedule for natural gas in accordance with **Appendix GG** attached to this permit.}

Continuous Monitoring Requirements

F.18. Continuous Monitoring System. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in specific conditions **F.8.** and **F.9.**, shall be reported to the DEP Southwest District office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction and fuel switching shall be monitored, recorded and reported as excess emissions when emission levels exceed the BACT standards listed in specific conditions **F.8.** and **F.9.** [PSD-FL-245 and 40 CFR 60.7.]

F.19. CEMS in lieu of Water to Fuel Ratio. Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1). Subject to EPA approval, calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emissions rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [PSD-FL-245.]

{Permitting note: The permittee may satisfy this condition for using the NOx CEMS in accordance with **Appendix GG** attached to this permit.}

F.20. Missing Data Substitution. When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time. [PSD-FL-245.]

F.21. Continuous Monitoring System. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. [PSD-FL-245.]

Test Methods and Procedures

F.22. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
ASTM D2880-71 or D4294 (or latest version) for the	Methods for Evaluating Fuel Sulfur Content

Method(s)	Description of Method(s) and Comment(s)
sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest version)	
EPA Method 9	Visual Determination of the Opacity of Emissions
EPA Method 10	Determination of Carbon Monoxide Emissions
EPA Reference Method 18, 25 and/or 25A	Determination of Volatile Organic Concentrations
EPA Method 7E	Determination of Nitrogen Oxide Emissions
EPA Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

F.23. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emissions standards for VE, CO and NO_X. The CO and NO_X RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

F.24. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance test shall be performed for the following pollutants: VE, CO and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

F.25. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

F.26. Compliance with the Allowable Emission Limiting Standards - Each Fuel. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days after initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the reference methods as described in the latest edition of 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C. [PSD-FL-245.]

F.27. Compliance Testing. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shakedown period not to exceed 100 days after restarting the combustion turbine) of air pollution control equipment, including installation of Ultra Low NO_X burners, Hot SCR, or conventional SCR. [PSD-FL-245.]

F.28. Continuous Compliance with the NO_X Emission Limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEMS based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not included

periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200, F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [PSD-FL-245.]

F.29. Compliance with the SO_2 and PM/PM_{10} Emission Limits. Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM/PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). [PSD-FL-245.]

F.30. Compliance with CO Emissions/Performance Criteria. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only). [PSD-FL-245.]

F.31. Compliance with the VOC Emissions/Performance Criteria. The CO emission limit will be employed as a surrogate and no annual testing for VOC emissions is required. [PSD-FL-245.]

Record Keeping and Reporting Requirements

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

F.32. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**F.36.**
Quarterly Excess Emissions, if requested	Every 3 months (quarter)	**F.33.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

F.33. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District office within one (1) working day of: the nature, extent, and duration of the excess emissions; and, the actions taken to correct the problem. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.; and, PSD-FL-245.]

Miscellaneous Requirements

F.34. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [PSD-FL-245.]

F.35. Compliance Plan. Based on the application for Permit No. 1050004-016-AV, initial compliance has been demonstrated for natural gas firing, but not for distillate fuel oil firing. **Appendix CP, Compliance Plan** for McIntosh Unit 5, is attached as a part of this permit. [Rule 62-213.440(2), F.A.C.]

F.36. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

F**.37.** NSPS Requirements - Subpart GG. Except as otherwise provided in this permit, the combustion turbine shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(8)(b), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.334(b)(2) and 40 CFR 60.335(f)(1). The Subpart GG requirement to correct test data to ISO conditions applies, but such correction is not required to demonstrate compliance with the non-NSPS permit standard(s). This emissions unit shall comply with **Appendix 40 CFR 60 Subpart GG** attached to this permit. [Rule 62-204.800(8)(b)39., F.A.C.]

Operated by: Lakeland Electric
Plant Name: C. D. McIntosh, Jr. Power Plant
ORIS code: 0676

Subsection A. This Subsection addresses Acid Rain, Phase II SO_2.

The emissions units listed below are regulated under Phase II SO_2 of the federal Acid Rain Program.

E.U. ID No.	Brief Description
-001	Boiler - McIntosh Unit 1
-005	Boiler - McIntosh Unit 2
-006	Boiler - McIntosh Unit 3
-028	McIntosh Unit 5 – 370 MW Combined Cycle Stationary Combustion Turbine

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

a. DEP Form No. 62-210.900(1)(a) - Form, Effective: 3/16/08, received on July 3, 2008, and signed by the Designated Representative on June 16, 2008, which is included at the end of this section.

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

A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID No.	Year	2009	2010	2011	2012	2013
-001	No. 01	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	907*	908*	908*	908*	908*
-005	No. 02	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	1029*	1031*	1031*	1031*	1031*
-006	No. 03	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	9928*	9948*	9948*	9948*	9948*
-028		SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*	0*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2, 3, or 4 of 40 CFR 73.

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

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, Fast-Track Revisions of Acid Rain Parts. [Rule 62-213.413, F.A.C.]

A.5. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator. [40 CFR 70.6(a)(1)(ii); and Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

A.6. Comments, notes, and justifications: None.

Acid Rain Part Application

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

This submission is: ☐ New ☐ Revised ■ Renewal

STEP 1

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

Plant name	State	ORIS/Plant Code
C.D. McIntosh, Jr. Power Plant	FL	0676

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
EU 001	No	Yes	N/A	N/A
EU 005	No	Yes	N/A	N/A
EU 006	No	Yes	N/A	N/A
EU 028	No	Yes	N/A	N/A

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

1

C.D. McIntosh, Jr. Power Plant

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

C.D. McIntosh, Jr. Power Plant
Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

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

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

In column "h" enter the hours.

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

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Effective: 3/16/08

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C.D. McIntosh, Jr. Power Plant

Plant Name (from STEP 1)

STEP 5

For SO_2 Opt-in units only.

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

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

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

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

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 N/A	Date N/A

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.

Subject: Acid Rain Part Application (C. D. McIntosh, Jr. Power Plant)

Name Mr. Timothy Bachand, P.E.	Title Manager of Engineering
Owner Company Name Lakeland Electric	
Phone (863) 834-6633	E-mail address timothy.bachand@lakelandelectric.com
Signature [signature]	Date 6/16/08

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Effective: 3/16/08

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Subsection B. This subsection addresses Acid Rain, Phase II NO_X.

{Permitting note: The U.S. EPA issued Acid Rain Phase I NO_X permit(s)}

The emissions units listed below are regulated under Phase II NO_X of the federal Acid Rain Program.

E.U. ID No.	Brief Description
-006	Boiler - McIntosh Unit 3

B.1. The Acid Rain Phase II NO_X Compliance Plan application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. Phase II NO_X Compliance Plan, EPA Form 7610-28 (3-97), dated June 16, 2008, which is included at the end of this section.

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

B.2. Nitrogen oxide (NO_X) requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID No.	NO_X limit [1]
-006	No. 03	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2009 through calendar year 2013. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

[1] Based on the Phase II NO_X Compliance Plan, EPA Form 7610-28 (3-97), dated June 16, 2008.

B.3. Comments, notes, and justifications: none.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Compliance Plan

Page 1 of 2

For more information, see instructions and refer to 40 CFR 76.9

This submission is : [X] New [ ] Revised

Step 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
C.D. McIntosh, Jr. Power Plant	FL	0676

Step 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "GB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 03 (EU006) Type DBW	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 05.0 lb/mmBtu (for Phase I dry bottom wall-fired boilers)						
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)						
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in						
(d) standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	X					
(e) Standard annual average emission limitation of 4.0 lb/mmBtu (for Phase II tangentially fired boilers)						
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)						
(g) Standard annual average emission limitation of .086 lb/mmBtu (for cyclone boilers)						
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						
(j) NO_x Averaging Plan (include NO_x Averaging form)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(I)(A)(check the standard emission limitation applicable to any unit utilizing stack)						
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(I)(B) with NOX Averaging (check the NOX Averaging Plan box and include NOX Averaging form)						

EPA Form 7610-28 (3-97)

C.D. McIntosh, Jr. Power Plant

Plant Name (from Step 1)

NOX Compliance – Page 2

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Step 2, cont'd

	ID# / Type	ID# / Type	ID# / Type	ID# / Type	ID# / Type	ID# / Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

Step 3
Read the standard requirements and certification, enter the name of the designated representative, sign &

Standard Requirements

General. This source is subject to the standard requirement in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(I)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by approved early election plan shall be subject to an emissions limitation for NO_X as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(ii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1,200, for fulfilling the obligations specified in 40 CFR part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or january1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year for which there is a failure to demonstrate compliance, and the designated representative may no submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated reprsentive must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_X for phase II units with Group 1boilers under 40 CFR 76.7 If an early election plan is terminated on or after 2000,the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

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

Subject: C.D. McIntosh, Jr. Power Plant Renewal Phase II NOx Compliance Plan Form

Name Timothy Bachand, P. E.	
Signature	Date 6/16/08

EPA Form 7610-28 (3-97)

SECTION V. APPENDICES.

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A, Glossary.
Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 2, 1997).
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix CP, Compliance Plan.
Appendix 40 CFR 60, Subpart A - General Provisions.
Appendix 40 CFR 60, Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators.
Appendix 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix RR, Facility-wide Reporting Requirements.
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.
Appendix U, List of Unregulated Emissions Units and/or Activities.
Appendix W501G McIntosh #5, Lakeland FL - Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01).

REFERENCED ATTACHMENTS.

The Following Attachments Are Included for Applicant Convenience:

Table 1, Summary of Air Pollutant Standards and Terms.
Table 2, Compliance Requirements.
Table H, Permit History.