


MEMORANDUM

TO: Scott Sheplak, P.E.
FROM: Edward J. Svec 
DATE: May 14, 2001

Re: Intent package for Combined Draft Air Construction Permit 1050004-010-
AC and DRAFT Title V Permit Revision No.: 1050004-011-AV
Lakeland Electric
C. D. McIntosh, Jr. Power Plant

Permit Clock: Today is ARMS Day 82
Day 90: May 22, 2001

The subject of this permit revision is to increase the heat input while operating on natural gas for the gas turbine designated as Unit 5, Emissions Unit I.D. No. -028.

I recommend that this Intent to Issue be sent out as attached.

SS/es
[electronic file name: memo-d.doc]



Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-010-AV
Permit No.: 1050004-011-AC

Project type: Combined AC/Title V Permit Revision - Unit No. 5 Heat Input

I HEREBY CERTIFY that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).



Scott M. Sheplak

Scott M. Sheplak, P.E.
Registration Number: 0048866
date

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 904/921-9532
Fax: 904/922-6979

**PUBLIC NOTICE OF INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE
V OPERATION PERMIT REVISION**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Air Construction Permit No. 1050004-010-AC (PSD-FL-245C)
Title V Operation Permit Revision No.: 1050004-011-AV

Lakeland Electric
C. D. McIntosh, Jr. Power Plant
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue a combined Air Construction Permit/Title V Operation Permit Revision to the Lakeland Electric for the C. D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive, Lakeland, Polk County. The applicant's name and address are Lakeland Electric, 501 East Lemon Street, Lakeland, Florida 33801-5079.

The Department will issue the combined Draft Air Construction Permit/Title V PROPOSED Operation Permit Revision, and subsequent combined Final Air Construction Permit/ Title V FINAL Operation Permit Revision, in accordance with the conditions of the attached Draft Air Construction Permit/ Title V DRAFT Operation Permit Revision unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department has determined that a combined Air Construction Permit/ Title V Operation Permit Revision is required in order to: increase the maximum heat input to Unit # 5 when operating on natural gas, which was established by permit PSD-FL-245 and incorporated in the current Title V operating permit.

The Department will accept written comments concerning the proposed combined Draft Air Construction Permit/Title V DRAFT Operation Permit Revision for a period of thirty (30) days from the date of publication of this notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this combined Draft Air Construction Permit/Title V DRAFT Operation Permit Revision, the Department shall issue a combined Revised Draft Air Construction Permit/Title V DRAFT Operation Permit Revision and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

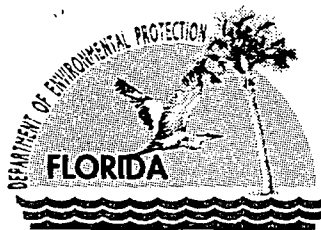
In addition to the above, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-1344
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

The complete project file includes the application, the Technical Evaluation and Preliminary Determination, combined Draft Air Construction Permit/Title V DRAFT Operation Permit Revision, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, Title V Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.



Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
May 16, 2001

David B. Struhs
Secretary

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger D. Harr, City Manager
Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: DEP File No. 1050004-010-AC (PSD-FL-245C)
Title V DRAFT Operation Permit Revision 1050004-011-AV
C. D. McIntosh, Jr. Power Plant

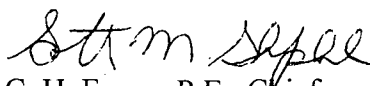
Dear Mr. Harr:

Enclosed is one copy of the Technical Evaluation and Preliminary Determination and associated combined Air Construction Permit/Title V DRAFT Operation Permit Revision, for the C. D. McIntosh, Jr. Power Plant in Polk County. The Department's "INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION" and the "PUBLIC NOTICE OF INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION" must be published one time only, as soon as possible, the legal advertising section of a newspaper of general circulation in the area affected, pursuant to the requirements of Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Scott Sheplak, P.E., Administrator, Title V Section at the above letterhead address. If you have any questions, please call Mr. Edward J. Svec at 850/921-8985.

Sincerely,

for 
C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/es

Enclosures

U.S. EPA, Region 4 (INTERNET E-mail Memorandum) ^{"More Protection, Less Process"}

Printed on recycled paper.

In the Matter of an
Application for Permit by:

Mr. Roger D. Harr
City Manager
Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Air Construction Permit No. 1050004-010-AC (PSD-FL-245C)
Title V Operation Permit Revision 1050004-011-AV
Increase to the Maximum Heat Input to Unit # 5
C. D. McIntosh, Jr. Power Plant
Polk County

INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION

The Department of Environmental Protection (Department) gives notice of its intent to issue a combined Air Construction Permit/ Title V Operation Permit Revision (copy of the combined Draft Air Construction Permit/ Title V DRAFT Operation Permit Revision is attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Lakeland Electric, applied on July 29, 2000, to the Department to increase the maximum heat input to Unit # 5 (E.U. ID No. -028) at the C. D. McIntosh, Jr. Power Plant in Polk County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-212, 62-213, and 62-214. The Department has determined that a combined Air Construction Permit/ Title V Operation Permit Revision is required in order to: increase the maximum heat input to Unit # 5 when operating on natural gas, which was established by permit PSD-FL-245 and incorporated in the current Title V operating permit.

The Department intends to issue this combined Air Construction Permit/ Title V Operation Permit Revision based on the belief that reasonable assurances have been provided to indicate that operation of the Title V source will not adversely impact air quality, and the Title V source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION." The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). The Department suggests that you publish the notice within thirty days of receipt of this letter. You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit or other authorization. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue combined Draft Air Construction Permit/ Title V PROPOSED Operation Permit Revision, and subsequent combined Final Air Construction Permit/ Title V FINAL Operation Permit Revision, in accordance with the conditions of the attached Draft Air Construction Permit/ Title V DRAFT Operation Permit Revision unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE A COMBINED AIR CONSTRUCTION PERMIT/TITLE V OPERATION PERMIT REVISION." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change to this combine Draft Air Construction Permit/ Title V DRAFT Operation

Permit Revision, the Department shall issue a combined Revised Draft Air Construction Permit/ Title V DRAFT Operation Permit Revision and require, if applicable, another Public Notice.

The Department will issue the PSD Permit Modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

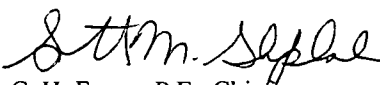
The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

Executed in Tallahassee, Florida.


for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE A COMBINED AIR CONSTRUCTION/TITLE V OPERATION PERMIT REVISION (including the combined Draft Air Construction Permit/Title V DRAFT Operation Permit Revision) and all copies were sent by certified mail before the close of business on 5/17/01 to the person(s) listed:

Roger D. Harr, City Manager, Lakeland Electric

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE A COMBINED AIR CONSTRUCTION/TITLE V OPERATION PERMIT REVISION (including the combined Draft Air Construction Permit/Title V DRAFT Operation Permit Revision) were sent by U.S. mail on the same date to the person(s) listed:

Farzie Shelton, Lakeland Electric
Bill Thomas, P.E., SWD

5/17/01 cc: Ed Ivec
Reading File

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Sunday 5/17/01
(Clerk) (Date)

SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 	<p>A. Received by (Please Print Clearly) B. Pulte B. Date of Delivery 5/21/01</p>
<p>1. Article Addressed to: Mr. Roger D. Harr City Manager Lakeland Electric 501 East Lemon Street Lakeland, Florida 33801-5079</p>	<p>C. Signature X B. Pulte <input type="checkbox"/> Agent <input type="checkbox"/> Addressee</p> <p>D. Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below: <input type="checkbox"/> No</p>
<p>2. Article Number (Copy from service label) 7000 0600 0021 6524 3950</p>	<p>3. Service Type <input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C.O.D.</p> <p>4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes</p>

PS Form 3811, July 1999

Domestic Return Receipt

102553-99-51-1789

U.S. Postal Service CERTIFIED MAIL RECEIPT <i>(Domestic Mail Only; No Insurance Coverage Provided)</i>											
<p>Article Sent To: Mr. Roger D. Harr</p>											
<table border="1"> <tr> <td>Postage</td> <td>\$</td> </tr> <tr> <td>Certified Fee</td> <td></td> </tr> <tr> <td>Return Receipt Fee (Endorsement Required)</td> <td></td> </tr> <tr> <td>Restricted Delivery Fee (Endorsement Required)</td> <td></td> </tr> <tr> <td>Total Postage & Fees</td> <td>\$</td> </tr> </table>	Postage	\$	Certified Fee		Return Receipt Fee (Endorsement Required)		Restricted Delivery Fee (Endorsement Required)		Total Postage & Fees	\$	<p>Postmark Here</p>
Postage	\$										
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Restricted Delivery Fee (Endorsement Required)											
Total Postage & Fees	\$										
<p>Name (Please Print Clearly) (to be completed by mailer) Mr. Roger D. Harr Street, Apt. No., or PO Box No. 501 East Lemon Street City, State, ZIP+4 Lakeland, Florida 33801-5079</p>											
<p>PS Form 3800, July 1999 See Reverse for Instructions</p>											

7000 0600 0021 6524 3950

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. Applicant

Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Authorized Representative: Roger D. Harr, City Manager

2. Source Name and Location

C. D. McIntosh, Jr. Power Plant
3030 East Lake Parker Drive
Lakeland, Florida 33805

UTM Coordinates: Zone 17, 409.0 km East and 3106.2 km North

3. Source Description

The C. D. McIntosh, Jr. Power Plant consists of three fossil fuel fired steam generators, two diesel powered generators, and two gas turbines. Fossil fuel fired steam generators 1 and 2 are fired with No. 6 fuel oil and natural gas with distillate oil used as an ignitor. Fossil fuel fired steam generator 3 is primarily fired with coal, refuse derived fuel 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 250 MW simple cycle stationary combustion turbine, fired with natural gas, or No. 2 or superior grade fuel oil with a maximum sulfur content of 0.05 percent by weight. The three fossil fuel fired steam generators and the simple cycle gas turbine are Acid Rain Units. Also included in this permit are several unregulated emissions units including storage tanks, a coal handling system and a wastewater treatment plant. Based on the Title V application, this facility is a major source of hazardous air pollutants (HAPs).

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.

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. McIntosh Unit 2 began commercial service in June, 1976.

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 to control emissions. McIntosh Unit 3 began commercial service in September, 1982.

McIntosh Unit 5 is a Westinghouse 501G combustion turbine operating in a simple cycle, once through steam generator. 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. Emissions are initially controlled using Dry Low NO_x combustion when firing natural gas; water injection when firing distillate fuel oil; use

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

of inherently clean fuels; and, good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions will be reduced by the use of either Ultra Low NO_x burners or the addition of a selective catalytic reduction (SCR) system. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion.

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. Diesel Engine Peaking Units 2 and 3 began commercial service in 1970.

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.

4. Current Permit and Major Regulatory Program Status

Lakeland Electric's C. D. McIntosh, Jr. Power Plant Units 1 and 2, Diesel Engines Units 2 and 3; and, Gas Turbine Peaking Unit 1 were granted operating permits as existing units by the Department. Construction of McIntosh Unit 3 was authorized by the Department under permit PSD-FL-008 and PA74-06SR. Unit 3 was modified by permits PSD-FL-008A, and again by permit PSD-FL-008B on December 11, 1995. Construction of McIntosh Unit 5 was authorized by the Department under permit PSD-FL-245 on July 10, 1998.

The facility operated under Title V Air Operation Permit No. 1050004-003-AV effective January 1, 1999. This initial permit was revised to include McIntosh Unit 5 and the facility currently operates under Title V Air Operation Permit No. 1050004-009-AV, which became effective November 19, 2000. This facility is a major source of hazardous air pollutants (HAPs) based on information submitted in the Title V application.

McIntosh Unit 1 is regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input.

McIntosh Unit 2 is regulated under Acid Rain, Phase II; 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(7), F.A.C.

McIntosh Unit 3 is regulated under Acid Rain, Phase II; 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(7), 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.

McIntosh Unit 5 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(7), F.A.C.; Rule 62-212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated July 10, 1998.

Diesel Engine Peaking Units 2 and 3 are regulated under Rule 62-210.300, F.A.C., Permits Required.

Gas Turbine Peaking Unit 1 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.

5. Permit Modification Request

On July 29, 2000 the Department received a request from Lakeland Electric for modification of its permits to increase the allowable heat input, when operating on natural gas, to Combustion Turbine (CT) Unit 5 (ARMS Emissions Unit 028). Unit 5 is a Siemens-Westinghouse 501G combustion turbine, rated at 250 megawatts, and is the first of this frame to be constructed and operated in the United States. During testing, it was discovered by the applicant that the turbine was capable of operation at higher heat inputs than the performance expectations of the technology from the engineering design.

The currently permitted 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, are 2,174 million Btu per hour when firing natural gas, and 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. The applicant has requested that the maximum heat input rate, when firing natural gas, be increased to 2,407 million Btu per hour at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure.

6. Emissions Increases Due to Modification/Method of Operation

The allowable emissions rates established for this emissions unit by permit PSD-FL-254, through a determination of Best Available Control Technology, are stated in units of parts per million. Since this unit description is a concentration, the mass emission rate will be dependent upon the mass flow rate in the exhaust stack. By increasing the maximum heat input, the maximum exhaust flow rate will then increase, thereby increasing the short-term emission rates for nitrogen oxides, carbon monoxide, sulfur dioxide and volatile organic compounds. The applicant estimates the emissions rates will increase, as follows:

TOTAL EMISSIONS INCREASES DUE TO INCREASE IN HEAT INPUT

Pollutant	Emission Rate lb/hour	Annual Increase tons/yr	PSD Threshold tons/yr
NO _x	262	18.0	40
CO	161	47.0	100
SO ₂	8	13.5	40
VOC	11	1.7	40

Source: Response to request for additional information received February 20, 2001.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

7. Evaluation of PSD Applicability

As a major source, a modification or change in method of operation of Unit 5 resulting in **significant net emissions increases** is subject to PSD review. Significant net emissions increase is defined in Rule 62-212.400, F.A.C as follows:

Significant Net Emissions Increase – A significant net emissions increase of a pollutant regulated under the Act is a net emissions increase equal to or greater than the applicable significant emission rate listed in Table 212.400-2, Regulated Air Pollutants – Significant Emission Rates.

The significant emission rates are included (see PSD Threshold) in the Table above. The meaning of a net emissions increase is given in Rule 62-212.400, F.A.C. as:

*Net Emissions Increase - A modification to a facility results in a net emissions increase when, for a pollutant regulated under the Act, the sum of all of the contemporaneous creditable increases and decreases in the **actual emissions** of the facility, including the increase in emissions of the modification itself and any increases and decreases in quantifiable fugitive emissions, is greater than zero.*

The definition of actual emissions is given in Rule 62-210.200, F.A.C. (definitions) as follows:

Actual Emissions - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:

- (a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.*
- (b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.*
- (c) For any emissions unit (other than an electric utility steam-generating unit specified in subparagraph (d) of this definition) which has not begun **normal operations** on a particular date, actual emissions shall equal the **potential emissions** of the emissions unit on that date.*
- (d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not*

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

The term electric utility steam-generating unit is defined as:

Electric Utility Steam Generating Unit – Any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the unit.

Since the net emissions increase for each pollutant is below the significant rate of those pollutants, the permitting action will not be subject to PSD review.

8. Proposed Addition of New Conditions to PSD-FL-245

The combustion turbine was constructed under the authority of PSD permit No. PSD-FL-245 issued on July 10, 1998. The PSD permit will be changed for natural gas combustion, as follows:

The maximum heat input specified in specific condition 8 will be changed to 2,407 million Btu per hour at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure; the nitrogen oxides emission rate of specific condition 21, in effect until May 1, 2002, will increase to 262 pounds per hour; the carbon monoxide emission rate of specific condition 22, in effect until May 1, 2002, will increase to 161 pounds per hour; the sulfur dioxide emission rate of specific condition 23 will increase to 8 pounds per hour; and, the volatile organic compounds emission rate of specific condition 25 will increase to 11 pounds per hour. In addition, the permit will incorporate the new curve of the maximum heat input as a function of compressor inlet temperature dated January 5, 2001, and supplied by the applicant in the permit application.

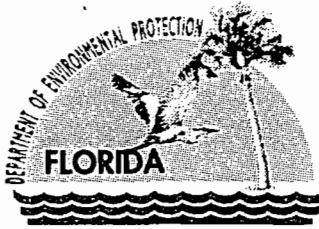
9. Conclusions

The project will increase the maximum short-term emission rates for nitrogen oxides, carbon monoxide, sulfur dioxide and volatile organic compounds. However, these increases are all below the significant net emission rates.

The Department concludes that PSD is not applicable to this project since this project as presented will not result in significant net emissions increase to major facility. The changes will not cause a significant impact or cause or contribute to a violation of any ambient air quality standard or PSD increment.

For further details regarding this review, contact:

*Scott Sheplak, P.E. Administrator
Edward Svec, Review Engineer
Title V Section
Bureau of Air Regulation
850/488-1344*



Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

DRAFT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger D. Harr
City Manager
Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Re: Permit Amendment No. 1050004-010-AC (PSD-FL-245C)
Amendment to Permit No. 1050004-04-AC (PSD-FL-245)
C. D. McIntosh, Jr. Power Plant

Dear Mr. Harr:

The Department has reviewed Lakeland Electric's request of February 20, 2001 requesting an amendment to its permit (1050004-004-AC, PSD-FL-245) to increase the maximum heat input rate to McIntosh Unit 5 when firing natural gas. This request is acceptable and the permit is hereby amended as follows:

FROM:

8. 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 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr 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 corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
[1050004-004-AC]
21. Nitrogen Oxides (NO_x) Emissions:
 - 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.
 - Until May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 237 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O₂, full load) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3 hr average) except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 25 ppm @15% O₂ nor 237 lb/hr (gas) and shall exceed neither 42 ppm @15% O₂ nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
 - Not later than May 1, 2002, the concentration of NO_x concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15% O₂) when firing natural gas and 42

"More Protection, Less Process"

ppmvd at 15% O₂ when firing fuel oil on the basis of a 3 hr average except during periods of startup, shutdown, malfunction or fuel switching, as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 9 ppm @15% O₂ nor 85 lb/hr (gas) and shall exceed neither 42 ppm @15% O₂ nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

- If Hot SCR is installed, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O₂ when firing natural gas. NO_x emissions shall not exceed 9 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 85 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O₂ when firing natural gas. If conventional SCR catalyst is installed, NO_x emissions shall not exceed 7.5 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 71.1 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

[1050004-004-AC]

22. Carbon Monoxide (CO) emissions: Prior to May 1, 2002, the concentration of CO (@15% O₂ in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 145 lb/hr (gas) and 539 lb/hr (oil). [Rule 62-212.400, F.A.C.]

After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (gas) and 386 lb/hr (oil). [Rule 62-212.400, F.A.C.]
[1050004-004-AC]

23. Sulfur Dioxide (SO₂) emissions: SO₂ emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO₂ shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]
[1050004-004-AC]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 10 lb/hr (gas) and 25 lb/hr (oil). [Rule 62-212.400, F.A.C.]
[1050004-004-AC]

TO:

8. 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 (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr 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 corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
[1050004-010-AC]

21. Nitrogen Oxides (NO_x) Emissions:

- 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.
- Until May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 262 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O₂, full load) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3 hr average) except during periods of startup, shutdown, malfunction or fuel switching, as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 25 ppm @15% O₂ nor 262 lb/hr (gas) and shall exceed neither 42 ppm @15% O₂ nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- Not later than May 1, 2002, the concentration of NO_x concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15% O₂) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3 hr average except during periods of startup, shutdown, malfunction or fuel switching, as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 9 ppm @15% O₂ nor 85 lb/hr (gas) and shall exceed neither 42 ppm @15% O₂ nor 413 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If Hot SCR is installed, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O₂ when firing natural gas. NO_x emissions shall not exceed 9 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 85 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O₂ when firing natural gas. If conventional SCR catalyst is installed, NO_x emissions shall not exceed 7.5 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of 3-hr average (except during periods of startup, shutdown, malfunction or fuel switching), as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 71.1 lb/hr (gas) and 148 lb/hr (oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
[1050004-010-AC]

22. Carbon Monoxide (CO) emissions: Prior to May 1, 2002, the concentration of CO (@15% O₂ in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 161 lb/hr (gas) and 539 lb/hr (oil). [Rule 62-212.400, F.A.C.]

After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (gas) and 386 lb/hr (oil). [Rule 62-212.400, F.A.C.]
[1050004-010-AC]

23. Sulfur Dioxide (SO₂) emissions: SO₂ 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 sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO₂ shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]
[1050004-010-AC]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 11 lb/hr (gas) and 25 lb/hr (oil). [Rule 62-212.400, F.A.C.]
[1050004-010-AC]

Mr. Roger D. Harr
Page 4 of 4
Date

A copy of this letter shall be filed with the referenced permit (1050004-004-AC, PSD-FL-245) and shall become part of the permit.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/es

Enclosures

STATEMENT OF BASIS

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

Title V Air Operation Permit Revision DRAFT Title V Permit Revision No.: 105004-011-AV

The initial Title V air operation permit went final on December 31, 1997 and effective on January 1, 1998. This Title V air operation permit with revision 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 perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

The subject of the permit revision is for the increase of the maximum heat input of Unit No. 5 (Emissions Unit I.D. – 028), a simple cycle stationary combustion turbine, when combusting natural gas for the C. D. McIntosh, Jr. Power Plant, implemented by permit 1050004-010-AC and PSD-FL-245C. Unit No. 5 is an Acid Rain unit. The revised heat input curve “W501G McIntosh #5, Lakeland FL – Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01)” is also added to the attachments made a part of the permit.

As result of the revision, the following changes are made:

FROM:

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 2,174 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 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 condition **F.24.** shall satisfy periodic monitoring requirements for heat input.

[Rules 62-4.160(2), 62-210.200(PTE) and 62-213.440(1)(b)1.b., F.A.C.; and, PSD-FL-245]

F.12. Nitrogen Oxides. Until May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 237 pounds per hour (at ISO conditions) on a 24-hour block average (basis 25 ppm @ 15% O₂, full load) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 25 ppm @ 15% O₂ nor 237 pounds per hour (when firing natural gas) and shall exceed neither 42 ppm @ 15% O₂ nor 413 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.

[PSD-FL-245]

F.16. Carbon Monoxide. Prior to May 1, 2002, the concentration of CO (@ 15% O₂) in the exhaust gas when firing natural gas shall not exceed 25 ppmvd and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 145 pounds per hour (when firing natural gas) and 539 pounds per hour (when firing fuel oil).

[PSD-FL-245]

F.18. Sulfur Dioxide. SO₂ emissions (at ISO conditions) shall not exceed 7.2 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 (see specific conditions F.36.). Emissions of SO₂ shall not exceed 38.4 tons per year.
[PSD-FL-245 and Applicant Request to Escape PSD Review]

F.20. Volatile Organic Compounds. The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd and 10 ppmvd when firing fuel oil as measured by EPA Method(s) 18 and/or 25A. VOC emissions (at ISO conditions) shall exceed 10 pounds per hour (when firing natural gas) and 25 pounds per hour (when firing fuel oil).
[PSD-FL-245]

TO:

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 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 condition F.24. shall satisfy periodic monitoring requirements for heat input.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-213.440(1)(b)1.b., F.A.C.; and, PSD-FL-245C]

F.12. Nitrogen Oxides. Until May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 262 pounds per hour (at ISO conditions) on a 24-hour block average (basis 25 ppm @ 15% O₂, full load) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 25 ppm @ 15% O₂ nor 262 pounds per hour (when firing natural gas) and shall exceed neither 42 ppm @ 15% O₂ nor 413 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.
[PSD-FL-245C]

F.16. Carbon Monoxide. Prior to May 1, 2002, the concentration of CO (@ 15% O₂) in the exhaust gas when firing natural gas shall not exceed 25 ppmvd and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 161 pounds per hour (when firing natural gas) and 539 pounds per hour (when firing fuel oil).
[PSD-FL-245C]

F.18. Sulfur Dioxide. SO₂ 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 (see specific conditions F.36.). Emissions of SO₂ shall not exceed 38.4 tons per year.
[PSD-FL-245C and Applicant Request to Escape PSD Review]

F.20. Volatile Organic Compounds. The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd and 10 ppmvd when firing fuel oil as measured by EPA Method(s) 18 and/or 25A. VOC emissions (at ISO conditions) shall exceed 11 pounds per hour (when firing natural gas) and 25 pounds per hour (when firing fuel oil).
[PSD-FL-245C]

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

Title V Air Operation Permit Revision
DRAFT Title V Permit Revision No.: 1050004-011-AV

Permitting Authority:

State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

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

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Title V Air Operation Permit Revision
DRAFT Title V Permit Revision No.: 1050004-011-AV
Table of Contents

Section	Page Number
Placard Page	1
I. Facility Information	2 - 4
A. Facility Description.	
B. Summary of Emissions Unit ID Nos. and Brief Descriptions.	
C. Relevant Documents.	
II. Facility-wide Conditions	5 - 6
III. Emissions Units and Conditions	
A. Emissions Unit -001 McIntosh Unit 1	7 - 17
B. Emissions Units -002 Diesel Engine Peaking Unit 2	18 - 22
-003 Diesel Engine Peaking Unit 3	
C. Emissions Unit -004 Gas Turbine Peaking Unit 1	23 - 28
D. Emissions Unit -005 McIntosh Unit 2	29 - 42
E. Emissions Unit -006 McIntosh Unit 3	43 - 61
F. Emissions Unit -028 McIntosh Unit 5	62 - 80
IV. Acid Rain Part	
A. Acid Rain, Phase II	81 - 82
B. Acid Rain, Phase I	83



Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

Permittee: **DRAFT Title V Permit Revision No.:** 1050004-011-AV
Lakeland Electric **Facility ID No.:** 1050004
501 East Lemon Street **SIC Nos.:** 49, 4911
Lakeland, Florida 33801-5079 **Project:** Title V Air Operation Permit Revision

This permit revision is for the increase of the maximum heat input of Unit No. 5, a simple cycle stationary combustion turbine, when combusting natural gas for the C. D. McIntosh, Jr. Power Plant. Unit No. 5 is an Acid Rain unit. This facility 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.

STATEMENT OF BASIS: This Title V air operation permit revision 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 perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-3, Title V Conditions (version dated 04/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND
MONITORING SYSTEM PERFORMANCE REPORT (40 CFR 60; July 1996)
Phase II Acid Rain Application/Compliance Plan received 12/18/95
Phase II Acid Rain Application/Compliance Plan received 3/10/98
Alternate Sampling Procedure: ASP Number 97-B-01
Appendix 40 CFR 60 Subpart A - General Provisions (version dated 07/23/97)
Phase I/II NO_x Acid Rain Application/Compliance Plan received December 9, 1997
Statement of Basis
Appendix H-1, Permit History / ID Number Changes
W501G McIntosh #5, Lakeland FL - Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01)

Effective Date: January 1, 1999
Title V Permit Revision Effective Date:
Renewal Application Due Date: July 5, 2003
Expiration Date: December 31, 2003

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sms/es

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Section I. Facility Information.

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 generators 1 and 2 are fired with No. 6 fuel oil and natural gas with distillate oil used as an ignitor. Fossil fuel fired steam generator 3 is primarily fired with coal, refuse derived fuel 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 250 MW simple cycle stationary combustion turbine, 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.

Based on the initial Title V permit application received June 14, 1996 and the application for the revision to the Title V permit dated April 24, 2000, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-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 - 250 MW Simple Cycle Stationary Combustion Turbine

Unregulated Emissions Units and/or Activities

E.U.

<u>ID No.</u>	<u>Brief Description of Emissions Units and/or Activity</u>
-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 (Unit 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	Flyash handling and storage system
-029	1.05 million gallon storage tank for McIntosh Unit 5, subject only to the reporting requirements of 40CFR60, Subpart Kb

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit, however, are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 2-1, Summary of Compliance Requirements

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers

These documents are on file with permitting authority:

Initial Title V Permit Application received June, 14, 1996

Additional Information Request dated January 13, 1997

Additional Information Response received February 10, 1997

Additional Information received May 9, 1997

Letter received July 2, 1997 from Ms. Farzie Shelton

Additional Information received July 8, 1997

Letter received August 7, 1997 from Ms. Farzie Shelton

Letter received September 4, 1997 from Ms. Farzie Shelton

Title V Permit Revision Application received April 24, 2000

Letter received August 18, 2000 from Ms. Farzie Shelton

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}
2. **Not Federally Enforceable** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]
3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4., F.A.C.]
4. Prevention of Accidental Releases (Section 112(r) of CAA).
 - a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable; and,
 - b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]
5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]
6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. 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 (VOC) or organic solvents (OS) 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.; Proposed by applicant in the initial Title V permit application received June 14, 1996; Revised by a letter received August 7, 1997]

8. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: maintenance of paved areas; regular mowing of grass and care of vegetation; and limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996, as amended in a request received July 8, 1997]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.

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

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}

[Rule 62-214.420(11), F.A.C.]

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District office:

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPRCA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163

III. Emissions Section Unit.

Subsection A. This section addresses the following emissions unit(s).

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.

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

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

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

<u>Unit No.</u>	<u>MMBtu/hr Heat Input</u>	<u>Fuel Type</u>
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 CEM will not be a method of compliance for the determination of the heat input rate.

[Rules 62-4.160(2), 62-210.200(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.}

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition A.23.

[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.

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

Emission Limitations and Standards

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

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. See specific condition **A.21**.

[Rule 62-296.405(1)(e)3., F.A.C.; and, AO 53-243945]

A.11. "On-Specification" Used Oil. Only "on-specification" used oil generated by the City of Lakeland shall be fired in this unit. The quantity fired in this unit shall not exceed 1,000 barrels (42,000 gallons) per calendar year. "On-specification" used oil is defined as used oil that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired.

<u>CONSTITUENT / PROPERTY *</u>	<u>ALLOWABLE LEVEL</u>
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by ASTM Standard D140-70, or equivalent
[40 CFR 279.11; and, AO 53-243945]

Excess Emissions

A.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

A.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

[Rule 62-210.700(2), F.A.C.]

A.14. 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.15. 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. See specific conditions **A.10., A.20. and A.21.**

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

A.16. Determination of Process Variables.

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.17. 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. See specific condition **A.18.**

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

A.18. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. 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.
2. 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:
 - a. 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.
 - b. 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.19. 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.20. 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 exceedences 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. See specific conditions A.10. and A.21.**

[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.; and, AO 53-243945]

A.21. 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.22. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

A.23. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.24. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

A.25. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

A.26. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

A.27. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) **General Compliance Testing.**

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

A.28. 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.

[Rule 62-297.310(7)(a)4., F.A.C.]

A.29. Annual and permit renewal compliance testing for particulate matter 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.

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

A.30. Compliance with the "on-specification" used oil requirements will be determined as follows:

- (a) Analysis of a sample collected from each batch delivered for firing; or,
- (b) The new batch delivery is from a collection site that has an acceptable analysis already on file with the facility and the analytical results are assumed by the facility for the batch.

For quantification purposes, the highest concentration of each constituent as determined by any analysis is assumed to be the concentration of the constituent of the blended used oil.

See specific condition **A.11.**

[AO 53-243945]

Record keeping and Reporting Requirements

A.31. 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.32. 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.]

A.33. Test Reports.

- (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
- (b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
- (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
 - 1. The type, location, and designation of the emissions unit tested.
 - 2. The facility at which the emissions unit is located.
 - 3. The owner or operator of the emissions unit.
 - 4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
 - 5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
 - 6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
 - 7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.34. Records shall be kept of each delivery of “on-specification” used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of “on-specification” used oil fired in this unit. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. [Rule 62-213.440(1)(b)2.b., F.A.C.; and, AO 53-243945]

A.35. The permittee shall include in the “Annual Operating Report for Air Pollutant Emitting Facility” a summary of the “on-specification” used oil analyses for the calendar year and a statement of the total quantity of “on-specification” used oil fired in Unit 1 during the calendar year. [AO 53-243945]

Section III. Emissions Unit(s) and Conditions.

Subsection B. This section addresses the following emissions unit(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-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. 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. Each diesel engine peaking unit has its own stack.}

The following specific conditions apply to the emissions units listed above:

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 [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]
- 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. [AO 53-244726]

{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.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.13.** [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.; and, AO 53-244726]

Emission Limitations and Standards

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

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.; and, AO 53-244726]

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.
[AO 53-244726]

Excess Emissions

B. 7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B. 8. 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.9. 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. See specific condition **B.12.**
[Rule 62-213.440, F.A.C.]

B.10. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.11. 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.12. 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.; and, AO 53-244726]

B.13. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.14. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

- c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.]

B.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

- a. Did not operate; or
- b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

- a. Visible emissions, if there is an applicable standard;

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 53-244726]

B.16. 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.

[Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

B.17. Malfunction Reporting. 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.]

B.18. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions unit(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-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.

{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.}

The following specific conditions apply to the emissions units listed above:

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.

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

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.

[AO 53-244727]

{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.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition C.13.

[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.; and, AO 53-244727]

Emission Limitations and Standards

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

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.; and, AO 53-244727]

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.
[AO 53-244727]

Excess Emissions

C.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.8. 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. 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. See specific condition **C.12**.
[Rule 62-213.440, F.A.C.]

C.10. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.11. 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.12. 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.; and, AO 53-244727]

C.13. Not federally enforceable. Operating Rate During Testing.

Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then sources may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 105 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.

[Requested in initial Title V permit application response for additional information dated February 10, 1997];

C.14. Applicable Test Procedures.

(a) Required Sampling Time.

2. **Opacity Compliance Tests.** When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

- c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.]

C.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

- a. Did not operate; or
- b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

- a. Visible emissions, if there is an applicable standard;

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 53-244727]

C.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units 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

C.17. Malfunction Reporting. 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.]

C.18. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions unit(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-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. McIntosh Unit 2 began commercial service in June, 1976.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; 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(7), F.A.C.}

The following conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

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

<u>Unit No.</u>	<u>MMBtu/hr Heat Input</u>	<u>Fuel Type</u>
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(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.}

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.23.**

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

Emission Limitations and Standards

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

Particulate Matter

D.5. 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:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

(2) 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)(1) & (2)]

Sulfur Dioxide

D.6. 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.

[40 CFR 60.43(a)(1)]

D.7. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

[40 CFR 60.43(c)]

Nitrogen Oxides

D.8. 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 NO₂ in excess of:

- (1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
 - (2) 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. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

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

where:

PS_{NO_x} = 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

{Permitting Note: 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. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

- (1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

[40 CFR 60.45(b)(2) and 60.45(g)(1)]

D.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

D.12. 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

D.13. Determination of Process Variables.

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.14. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).

[40 CFR 60.46(a)]

D.15. The owner or operator shall determine compliance with the particulate matter, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of particulate matter, or NO_x shall be computed for each run using the following equation:

$$E = C F_d (20.9)/(20.9 - \% O_2)$$

E = emission rate of pollutant, ng/J (1b/million Btu).

C = concentration of pollutant, ng/dscm (1b/dscf).

% O₂ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particulate matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of all the individual O₂ sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O₂ traverse points.

(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

(5) Method 7 shall be used to determine the NO_x concentration.

(i) The sampling site and location shall be the same as for the SO₂ sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample.

(iii) The NO_x emission rate shall be computed for each pair of NO_x and O₂ samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(1), (2), (3), & (5)]

D.16. 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.17.**

[Rule 62-213.440, F.A.C. and Applicant Request dated June 14, 1996]

D.17. 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 SO₂ emission rate to ensure compliance at all times.

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

D.18. When combinations of fossil fuels are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

- (1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.
- (2) ASTM Methods D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels.
- (3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

[40 CFR 60.46(c)(1), (2), & (3)]

D.19. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

- (1) The emission rate (E) of particulate matter, SO₂ and NO_x may be determined by using the F_c factor, provided that the following procedure is used:

- (i) The emission rate (E) shall be computed using the following equation:

$$E = C F_c (100 / \% \text{CO}_2)$$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

% CO₂ = carbon dioxide concentration, percent dry basis.

F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209 (F_{da} / F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than $0.97 F_{oa}$, then E shall be increased by that proportion under $0.97 F_{oa}$, e.g., if F_o is $0.95 F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than $0.97 F_{oa}$ and when the average difference (\bar{d}) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under $0.97 F_{oa}$, e.g., if F_o is $0.95 F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than $1.03 F_{oa}$ and when \bar{d} is positive, then E shall be decreased by that proportion over $1.03 F_{oa}$, e.g., if F_o is $1.05 F_{oa}$, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of $160^\circ C$ ($320^\circ F$). Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used.

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[40 CFR 60.46(d)(1), (2), (3), (5), (6), & (7)]

D.20. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

D.21. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.]

D.22. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

D.23. Applicable Test Procedures.

(a) **Required Sampling Time.**

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

D.24. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

D.25. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

D.26. 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.

[Rule 62-297.310(7)(a)4., F.A.C.]

D.27. Annual and permit renewal compliance testing for particulate matter 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.

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

Continuous Monitoring Requirements

D.28. The owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions.

[40 CFR 60.45(a)]

D.29. 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.** See specific condition **D.19.**

[40 CFR 60.45(b)(2)]

D.30. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent.

[40 CFR 60.45(c)(3)]

Recordkeeping and Reporting Requirements

D.31. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c).

[40 CFR 60.45(g)]

D.32. 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.]

D.33. 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 62-213.440, F.A.C.]

D.34. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
 7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
 8. The date, starting time and duration of each sampling run.
 9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
 10. The number of points sampled and configuration and location of the sampling plane.
 11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
 12. The type, manufacturer and configuration of the sampling equipment used.
 13. Data related to the required calibration of the test equipment.
 14. Data on the identification, processing and weights of all filters used.
 15. Data on the types and amounts of any chemical solutions used.
 16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
 17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
 18. All measured and calculated data required to be determined by each applicable test procedure for each run.
 19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
 20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
 21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.
- [Rule 62-297.310(8), F.A.C.]

Miscellaneous Requirements.

D.35. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.

[Rule 62-204.800(7)(d), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection E. This section addresses the following emissions unit(s).

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-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 to control emissions. McIntosh Unit 3 began commercial service in September, 1982.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; 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(7), 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 }

The following conditions apply to the emissions unit(s) listed above:

{Permitting note: 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 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(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.}

E.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **E.21**.
[Rule 62-297.310(2), F.A.C.]

E.22. When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

- (1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.
- (2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.
- (3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.
[40 CFR 60.46(c)(1), (2), & (3)]

E.23. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

- (1) The emission rate (E) of particulate matter, SO₂ and NO_x may be determined by using the F_c factor, provided that the following procedure is used:

- (i) The emission rate (E) shall be computed using the following equation:

$$E = C F_c (100 / \% \text{CO}_2)$$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

% CO₂ = carbon dioxide concentration, percent dry basis.

F_c = factor as determined in appropriate sections of Method 19.

- (ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O₂ and CO₂ concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., F_{oa} = 0.209 (F_{da} / F_{ca}), then the following procedure shall be followed:

- (A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than $0.97 F_{oa}$ and when the average difference (\bar{d}) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under $0.97 F_{oa}$, e.g., if F_o is $0.95 F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than $1.03 F_{oa}$ and when \bar{d} is positive, then E shall be decreased by that proportion over $1.03 F_{oa}$, e.g., if F_o is $1.05 F_{oa}$, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160°C (320°F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used.

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46(d)(1).

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%\text{O}_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[40 CFR 60.46(d)(1), (2), (3), (4), (5), (6), & (7)]

E.24. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

E.25. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.]

E.26. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

E.27. Applicable Test Procedures.

(a) **Required Sampling Time.**

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

- a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
- b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
- c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

E.28. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

E.29. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the _____ year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

- b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
- c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

E.30. 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.

[Rule 62-297.310(7)(a)4., F.A.C.]

E.31. Annual and permit renewal compliance testing for particulate matter 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.

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

Continuous Monitoring Requirements

E.32. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, and either oxygen or carbon dioxide except as provided in 40 CFR 60.45(b).

[40 CFR 60.45(a)]

E.33. Certain of the continuous monitoring system requirements under 40 CFR 60.45(a) do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) 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).

(3) Notwithstanding 40 CFR 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under 40 CFR 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in 40 CFR 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under 40 CFR 60.8 and comply with all other applicable monitoring requirements under 40 CFR 60.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under 40 CFR 60.45(b)(1) and (b)(3) or (b)(2) and (b)(3), a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

[40 CFR 60.45(b)(1), (2), (3), & (4)]

E.34. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

- (1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
- (2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
- (3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide
Gas.....	{1}
Liquid.....	1,000
Solid.....	1,500
Combinations.....	$1,000y+1,500z$

{1} Not applicable.

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

[40 CFR 60.45(c)(1), (2), (3), (4), & (5)]

E.35. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF[20.9/(20.9\text{-percent } O_2)]$$

where:

E, C, F, and % O₂ are determined under 40 CFR 60.45(f).

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c [100/\text{percent } CO_2]$$

where:

E, C, F_c and % CO₂ are determined under 40 CFR 60.45(f).
[40 CFR 60.45(e)(1) and (2)]

E.36. The values used in the equations under 40 CFR 60.45(e) (1) and (2) are derived as follows:

(1) E = pollutant emissions, ng/J (lb/million Btu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) % O₂, % CO₂ = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), $F = 2,723 \times 10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c = 0.532 \times 10^{-17}$ scm CO₂ /J (1,980 scf CO₂ /million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c = 0.486 \times 10^{-7}$ scm CO₂ /J (1,810 scf CO₂ /million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO₂ /J (1,430 scf CO₂ /million Btu).

(iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO₂ /J (1,040 scf CO₂ /million Btu) for natural gas, 0.322×10^{-7} scm CO₂ /J (1,200 scf CO₂ /million Btu) for propane, and 0.338×10^{-7} scm CO₂ /J (1,260 scf CO₂ /million Btu) for butane.

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO₂ /J, or scf CO₂ /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^{-6} \frac{[227.2 (\text{pct. H}) + 95.5 (\text{pct. C}) + 35.6 (\text{pct. S}) + 8.7 (\text{pct. N}) - 28.7 (\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0 \times 10^{-5} (\text{pct. C})}{\text{GCV}}$$

(SI units)

$$F = 10^6 \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{\text{GCV}}$$

(English units)

$$F_c = \frac{20.0(\%C)}{\text{GCV}}$$

(SI units)

$$F_c = \frac{321 \times 10^3 (\%C)}{\text{GCV}}$$

(English units)

- (i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)
- (ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)
- (iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.
- (6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^n X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^n X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or (F_c)_i = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.

[40 CFR 60.45(f)(1), (2), (3), (4), (5), & (6)]

E.37. 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 SO₂ reduction.

[PSD-FL-008(B)]

Recordkeeping and Reporting Requirements

E.38. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c). The summary report form shall contain the information and be in the format shown in figure 1 (attached to this permit) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

[40 CFR 60.7(d) & 60.45(g)]

E.39. 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.40. Submit to the Department a written report of emissions in excess of emission limiting 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 62-213.440, F.A.C.]

E.41. Test Reports.

- (a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
- (b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
- (c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:
1. The type, location, and designation of the emissions unit tested.
 2. The facility at which the emissions unit is located.
 3. The owner or operator of the emissions unit.
 4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
 5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
 6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
 7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
 8. The date, starting time and duration of each sampling run.
 9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
 10. The number of points sampled and configuration and location of the sampling plane.
 11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
 12. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

Miscellaneous Requirements.

E.42. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.

[Rule 62-204.800(7)(d), F.A.C.]

E.43. 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)]

Section III. Emissions Unit(s) and Conditions.

Subsection F. This section addresses the following emissions unit.

E.U. ID

<u>No.</u>	<u>Brief Description</u>
-028	McIntosh Unit 5 – 250 MW Simple Cycle Stationary Combustion Turbine

McIntosh Unit 5 is a Westinghouse 501G combustion turbine operating in a simple cycle, once through steam generator. 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. Emissions are initially controlled using Dry Low NO_x combustion when firing natural gas; water injection when firing distillate fuel oil; use of inherently clean fuels; and, good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions will be reduced by the use of either Ultra Low NO_x burners or the addition of a selective catalytic reduction (SCR) system. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion.

{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(7), 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. The simple cycle combustion turbine began operation in March, 2000.}

The following specific conditions apply to the emissions unit(s) listed above:

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 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 condition F.24. shall satisfy periodic monitoring requirements for heat input. [Rules 62-4.160(2), 62-210.200(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 specific condition **F.40.**
[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(PTE), F.A.C.; and, PSD-FL-245]

F.5. Fuel Usage as Heat Input.

(a) Natural Gas. Fuel usage as heat input shall not exceed 15.639×10^{12} Btu (LHV) per year (rolled monthly) until the unit achieves the NO_x emission limits (other than the initial limits) given in specific conditions **F.12.** through **F.15.** Thereafter, only the hourly heat input limits given in specific condition **F.1.** apply.

(b) Fuel Oil. Fuel usage as heat input shall not exceed 599×10^9 Btu (LHV) per year (rolled monthly).
[PSD-FL-245]

Control Technology

F.6. Westinghouse Dry Low NO_x (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides emissions while firing natural gas.
[PSD-FL-245]

F.7. The DLN combustors shall be replaced with Westinghouse Ultra Low NO_x (ULN) combustors to accomplish further NO_x control in order to achieve the emission limits specified in specific conditions **F.11.** through **F.15.** A high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system shall be installed and in operation (together with DLN or ULN combustors) not later than May 1, 2002, if the emission limits specified in specific conditions **F.11.** through **F.15.** are not achievable by ULN combustors by this date.
[PSD-FL-245]

F.8. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment and/or oxidation catalyst in the event that the ULN technology fails to achieve the NO_x limits given in specific conditions **F.11.** through **F.15.** or the carbon monoxide (CO) limits given in specific conditions **F.16.** and **F.17.** are not met.
[PSD-FL-245]

F.9. 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]

F.10. The permittee shall provide manufacturer's emissions performance verses load diagrams for the DLN and ULN systems prior to their installation. DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_x emissions and CO emissions. Operation of the DLN and ULN systems in the diffusion firing mode shall be minimized when firing natural gas.

[PSD-FL-245]

Emission Limitations and Standards

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

F.11. The following table is a summary of the BACT determination and is followed by the applicable specific conditions **F.12.** through **F.20.** Values for NO_x are corrected to 15% O₂. Values for CO are corrected to 15% O₂ only until May 1, 2002.

Operational Mode	NO _x (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG (basis) 237 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies until 05/1/2002 . Clean fuels, good combustion.
Simple Cycle	9 - NG (basis) 85 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 05/1/2002. Clean fuels, good combustion.
Simple Cycle	9 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies not later than 05/1/2002 if 9 ppm NO _x not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR unless simple cycle limits are achieved on or before 05/01/2002. Clean fuels, good combustion.

[PSD-FL-245]

F.12. Nitrogen Oxides. Until May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 262 pounds per hour (at ISO conditions) on a 24-hour block average (basis 25 ppm @ 15% O₂, full load) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 25 ppm @ 15% O₂ nor 262 pounds per hour (when firing natural gas) and shall exceed neither 42 ppm @ 15% O₂ nor 413 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.

[PSD-FL-245C]

F.13. Nitrogen Oxides. No later than May 1, 2002, the concentration of NO_x in the exhaust gas shall not exceed 85 pounds per hour (at ISO conditions) on a 24-hour block average (basis 9 ppm @ 15% O₂) when firing natural gas and 42 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall exceed neither 9 ppm @ 15% O₂ nor 85 pounds per hour (when firing natural gas) and shall not exceed 42 ppm @ 15% O₂ or 413 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.

[PSD-FL-245]

F.14. Nitrogen Oxides. If hot SCR is installed, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O₂ when firing natural gas. NO_x emissions shall not exceed 9 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 85 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.15. Nitrogen Oxides. If conventional SCR is installed in conjunction with the conversion to combined cycle operation, achievable short-term NO_x concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O₂ when firing natural gas. If conventional SCR catalyst is installed, NO_x emissions shall not exceed 7.5 ppmvd at 15% O₂ when firing natural gas and 15 ppmvd at 15% O₂ when firing fuel oil on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_x emissions calculated as NO₂ (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.16. Carbon Monoxide. Prior to May 1, 2002, the concentration of CO (@ 15% O₂) in the exhaust gas when firing natural gas shall not exceed 25 ppmvd and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 161 pounds per hour (when firing natural gas) and 539 pounds per hour (when firing fuel oil).

[PSD-FL-245C]

F.17. Carbon Monoxide. After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 pounds per hour (when firing natural gas) and 386 pounds per hour (when firing fuel oil).

[PSD-FL-245]

F.18. Sulfur Dioxide. SO₂ 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 (see specific conditions F.36.). Emissions of SO₂ shall not exceed 38.4 tons per year.
[PSD-FL-245C and Applicant Request to Escape PSD Review]

F.19. Visible Emissions. Visible emissions shall not exceed 10 percent opacity.
[PSD-FL-245]

F.20. Volatile Organic Compounds. The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd and 10 ppmvd when firing fuel oil as measured by EPA Method(s) 18 and/or 25A. VOC emissions (at ISO conditions) shall exceed 11 pounds per hour (when firing natural gas) and 25 pounds per hour (when firing fuel oil).
[PSD-FL-245C]

Excess Emissions

{Permitting note: 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.21. 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
[Rule 62-210.700(1), F.A.C.; and, PSD-FL-245]

F.22. 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.23. At all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR 60.11(d)]

F.24. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_x emissions shall operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ± 5.0 percent and shall be approved by the Administrator.

[40 CFR 60.334(a)]

F.25. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

- (1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.
- (2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).

[40 CFR 60.334(b)(1) & (2)]

F.26. 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). See specific condition

F.36.

[PSD-FL-245]

F.27. 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):

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in specific condition **F.36.** for the measurement of sulfur in gaseous fuels, or an approved alternate method. Once Unit 5 becomes operational, 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.
- 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.
- 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.
- 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.
- The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in specific condition **F.36.** are used.

[PSD-FL-245]

F.28. Determination of Process Variables.

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

F.29. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Department to determine the nitrogen content of the fuel being fired.
[40 CFR 60.335(a)]

F.30. During performance tests to determine compliance, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$\text{NO}_x = [\text{NO}_x \text{ obs}] [(P_{\text{ref}})^{0.5} / P_{\text{obs}}] e^{19} [H_{\text{obs}} - 0.00633] [288^\circ \text{K} / T_{\text{amb}}] 1.53$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

NO_x obs = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

e = Transcendental constant (2.718)

H_{obs} = Specific humidity of ambient air at test.

T_{amb} = Temperature of ambient air at test.

[40 CFR 60.335(c)(1)]

F.31. When determining compliance with 40 CFR 60.332, Subpart GG - Standards of Performance for Stationary Gas Turbines, the monitoring device of 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the permitted NO_x standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.
[40 CFR 60.335(c)(2)]

F.32. The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows:

c. U.S. EPA Method 20 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_x emissions shall be determined at each of the load conditions specified in 40 CFR 60.335(c)(2).

[40 CFR 60.335(c)(3)]

F.33. 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. Emission limit compliance dates shall conform to the timetable specified in specific condition **F.11**.

[PSD-FL-245]

F.34. 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. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 – September 30) pursuant to Rule 62-297.310(7), F.A.C., on Unit 5, as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, “Visual Determination of the Opacity of Emissions from Stationary Sources” (I,A).
- EPA Reference Method 10, “Determination of Carbon Monoxide Emissions from Stationary Sources” (I,A).
- EPA Reference Method 20, “Determination of Oxides of Nitrogen, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.” Initial test only for compliance with 40 CFR 60, Subpart GG and (I,A) short-term NO_x BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for the annual test requirement).
- EPA Reference Method(s) 18 and/or 25A, “Determination of Volatile Organic Concentrations.” Initial test only.

[PSD-FL-245]

F.35. Continuous compliance with the NO_x emission limits: Continuous compliance with the NO_x emission limits shall be demonstrated with the CEM system 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 include 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 in specific condition **F.59**. 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.36. Compliance with the SO₂ and PM/PM₁₀ emission limits: Notwithstanding 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 SO₂ and PM/PM₁₀. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO₂ 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.37. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_x test, as required. The initial NO_x and CO test results shall be the average of three valid one-hour runs. 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.38. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required.
[PSD-FL-245]

F.39. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and (d) to determine the nitrogen and sulfur contents of the fuel being burned. The 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. See specific conditions **F.25.** through **F.27.**
[40 CFR 60.335(e)]

F.40. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input verses ambient temperature). If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than permitted capacity. In this case, subsequent emissions unit operation is limited by adjusting the entire heat input verses ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.; and, PSD-FL-245]

F.41. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

F.42. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

F.43. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.

Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

F.44. The permittee shall comply with the requirements contained in APPENDIX SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

F.45. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

8. Any combustion turbine that does not operate for more than 400 hours per year shall term of its air operation permit.

9. The owner or operator shall notify the Department's Southwest District office, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department's Southwest District office, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

Continuous Monitoring Requirements

F.46. 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.11. through F.15., 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.11. through F.15.

[PSD-FL-245 and 40 CFR 60.7]

F.47. 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) specified in specific condition F.55. Subject to EPA approval, calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) and specified in specific condition F.31. 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]

F.48. 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.49. A performance evaluation of the CEMS shall be conducted during any required performance test or within 30 days thereafter in accordance with the applicable performance specifications of 40 CFR 60, Appendix B and at other times as required by the Administrator.
[40 CFR 60.13(c)]

F.50. The zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts shall be checked at least once daily in accordance with a written procedure. The zero and span shall, at a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications of 40 CFR 60, Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified.
[40 CFR 60.13(d)(1)]

F.51. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d)(1), all continuous monitoring systems shall be in continuous operation and shall meet the minimum frequency of operation as follows:

(2) All continuous monitoring systems for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)]

F.52. All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained.
[40 CFR 60.13(f)]

F.53. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdown, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g. ppm pollutant and percent O₂ or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit. (e.g. rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

F.54. 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]

Record Keeping and Reporting Requirements

F.55. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

a. Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the permitted nitrogen oxide standard by the initial performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the initial performance test. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

[Rule 62-296.800, F.A.C.; and, 40 CFR 60.334(c)(1)]

F.56. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate).

Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

Quarterly excess emission reports, in accordance with 40 CFR 60.7(a)(7)(c), shall be submitted to the DEP's Southwest District office.

[40 CFR 60.7(c)(1), (2), (3), & (4); and, PSD-FL-245]

F.57. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[40 CFR 60.7(d)(1) & (2)]

F.58. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

- (i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
- (ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and
- (iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

F.59. 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]

F.60. All recorded data shall be maintained on file by the Source for a period of five years.

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

F.61. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District office on the results of each such test.

(b) The required test report shall be filed with the Department's Southwest District office as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's Southwest District office to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department's Southwest District office or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Requirements.

F.62. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.

[40 CFR 60.2; and, Rule 62-204.800(7)(a), F.A.C.]

F.63. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR 60.12]

F.64. 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]

Section IV. This section is the Acid Rain Part.

Operated by: Lakeland Electric
ORIS code: 676

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

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

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 – 250 MW Simple Cycle Stationary Combustion Turbine

A.1. The Phase II permit 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. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

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

A.2. Sulfur dioxide (SO₂) allowance allocations for each Acid Rain unit is as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-001	No. 01	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	907*	907*	907*	907*
-005	No. 02	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	1029*	1029*	1029*	1029*
-006	No. 03	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	9928*	9928*	9928*	9928*
-028		SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	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 or 3 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.

1. 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.

2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

3. 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, F.A.C.

[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: None.

Subsection B. This subsection addresses Acid Rain, Phase I.

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

The emissions unit listed below is regulated under Acid Rain Part, Phase I, for Lakeland Electric, C. D. McIntosh, Jr. Power Plant, **Facility ID No.:** 1050004, **ORIS code:** 676

E.U.

<u>ID No.</u>	<u>Brief Description</u>
-006	Boiler - McIntosh Unit 3

B.1. The owners and operators of these Phase I acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:

- a. Phase I permit dated 03/27/97.
 [Chapter 62-213, F.A.C.]

B.2. Nitrogen oxide (NO_x) requirements for the following Acid Rain unit is as follows:

<u>E.U. ID No.</u>	<u>EPA ID</u>	<u>NO_x limit*</u>
-006	No. 03	<p>Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_x early election compliance plan for unit No. 03. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008.</p> <p>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.</p>

* Based on the Phase II NO_x Compliance Plan dated December 4, 1997.

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

Appendix U-1, List of Unregulated Emissions Units and/or Activities.

Lakeland Electric & Water Utilities **DRAFT Permit Revision No.:** 1050004-011-AV
C. D. McIntosh, Jr. Power Plant **Facility ID No.:** 1050004

Unregulated Emissions Units and/or Activities. An emissions unit which emits no “emissions-limited pollutant” and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither ‘regulated emissions units’ nor ‘insignificant emissions units’.

E.U.

<u>ID No.</u>	<u>Brief Description of Emissions Units and/or Activity</u>
-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 (Unit 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	Flyash handling and storage system
-029	1.05 million gallon fuel storage tank for McIntosh Unit 5, subject only to the reporting requirements of 40 CFR 60, Subpart Kb

Appendix I-1, List of Insignificant Emissions Units and/or Activities.

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Diesel Storage Tank (T-021)
2. Heavy Oil Tank (T-113)
3. Heavy Oil Tank (T-114)
4. Heavy Oil Tank (T-115)
5. Used Oil Tank (T-116)
6. Comfort Heating <1 MMBtu/hr
7. Non-Industrial Vacuum Cleaning
8. Refrigeration Units
9. Vacuum Pumps for Labs
10. Steam Cleaning Equipment
11. Sanders <5 square feet
12. Space Heating Equipment; non-boilers
13. Bakery Ovens
14. Lab Equipment
15. Brazing, Soldering, or Welding
16. Laundry Dryers
17. Fire and Safety Equipment
18. Surface Coating <5% VOC

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

- Coal only
- Low sulfur fuel oil only (≤ 0.5 percent sulfur by weight)
- Coal and up to 10 percent refuse (based on heat input)
- Low sulfur fuel oil and up to 10 percent refuse (based on heat input)
- Coal and up to 20 percent petroleum coke (based on weight)
- Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input)
- High sulfur fuel oil (> 0.5 percent sulfur by weight)
- 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, 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(PTE), F.A.C.]

Emission Limitations and Standards

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

Particulate Matter

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

(1) <u>Mode of Firing</u>	<u>Pound / MMBtu Heat Input</u>
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

(2) 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); and, PSD-FL-008(B)]

Sulfur Dioxide

E.6. 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.
 - (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.7. 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:

$$PS_{SO_2} = [y(340) + z(520)] / (y+z)$$

where:

PS_{SO_2} 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)]

E.8. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

[40 CFR 60.43(c)]

E.9. 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. 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 SO₂ 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. 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 SO₂ 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. 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 SO₂ scrubber will be allowed.

[PSD-FL-008(B)]

Nitrogen Oxides

E.13. 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 NO₂ in excess of:

- (1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
- (2) 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.
- (3) 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. 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:

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

where:

PS_{NO_x} = 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

{Permitting Note: 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.15. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

[40 CFR 60.45(g)(1), & (2)]

E.16. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

E.17. 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.]

E.18. 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]

Monitoring of Operations

E.19. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.20. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).

[40 CFR 60.46(a)]

E.21. The owner or operator shall determine compliance with the particulate matter, SO₂, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of particulate matter, SO₂, or NO_x shall be computed for each run using the following equation:

$$E = C F_d (20.9)/(20.9 - \% O_2)$$

E = emission rate of pollutant, ng/J (1b/million Btu).

C = concentration of pollutant, ng/dscm (1b/dscf).

% O₂ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particulate matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of all the individual O₂ sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O₂ traverse points.

(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO₂ concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The O₂ sample shall be taken simultaneously with, and at the same point as, the SO₂ sample. The SO₂ emission rate shall be computed for each pair of SO₂ and O₂ samples. The SO₂ emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_x concentration.

(i) The sampling site and location shall be the same as for the SO₂ sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample.

(iii) The NO_x emission rate shall be computed for each pair of NO_x and O₂ samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(1), (2), (3), (4), & (5)]

Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description**
I-0011 McIntosh Unit 1 - Fossil Fuel Fired Steam Generator

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
VE	All	8,760	20% w/ 40% for 2 min/hr					62-296.405(1)(a),FAC	III.A.5.
VE	All		60% 3 hrs/24 hrs					62-210.700(3),FAC	III.A.6.
PM	Gas	8,760	0.1 lb/MMBtu			98.5	431.4	62-296.405(1)(b),FAC	III.A.7.
PM	Oil	8,760	0.1 lb/MMBtu			98.0	416.1	62-296.405(1)(b),FAC	III.A.7.
PM	Gas	1,095	0.3 lb/MMBtu			286.5	161.8	62-210.700(3),FAC	III.A.8.
PM	Oil	1,095	0.3 lb/MMBtu			286.0	156.0	62-210.700(3),FAC	III.A.8.
SO ₂	Oil	8,760	2.75 lb/MMBtu			2,612.5	11,442.8	62-296.405(1)(c)1.j.,FAC	III.A.9.
SO ₂	Oil	8,760	2.5% S by weight			2,612.5	11,442.8	AO 53-243945	III.A.10.
Arsenic	Used Oil		5 ppm (42,000 gal/yr)				0.0008	AO 53-243945	III.A.11.
Cadmium	Used Oil		2 ppm (42,000 gal/yr)				0.0003	AO 53-243945	III.A.11.
Chromium	Used Oil		10 ppm (42,000 gal/yr)				0.0017	AO 53-243945	III.A.11.
Lead	Used Oil		100 ppm (42,000 gal/yr)				0.017	AO 53-243945	III.A.11.
Total Halogens	Used Oil		1,000 ppm (42,000 gal/yr)				0.17	AO 53-243945	III.A.11.
PCBs	Used Oil		< 50 ppm (42,000 gal/yr)				0.0084	AO 53-243945	III.A.11.

Notes:

* The "Equivalent Emissions" listed are for informational purposes only.

Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
VE	All	8,760	< 20%					62-296.320(4)(b)1., FAC	III.B.5.
SO ₂	Oil	8,760	0.5% S by weight			15.4	67.5	AO 53-244726	III.B.6.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

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Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
 C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
VE	All	8,760	< 20%					62-296.320(4)(b)1., FAC	III.C.5.
SO ₂	Oil	8,760	0.5% S by weight			176.0	770.8	AO 53-244727	III.C.6.

Notes:
 * The "Equivalent Emissions" listed are for informational purposes only.

[electronic file name: 10500041.xls]

Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
PM	Gas	8,760	0.10 lb/MMBtu			118.8	518.8	40 CFR 60.42(a)(1)	III.D.5.
PM	Oil	8,760	0.10 lb/MMBtu			111.6	488.4	40 CFR 60.42(a)(1)	III.D.5.
VE	All	8,760	20% w/ 27% for 6 min/hr					40 CFR 60.42(a)(2)	III.D.5.
SO ₂	Oil	8,760	0.80 lb/MMBtu			892.0	3,907.0	40 CFR 60.43(a)(1)	III.D.6.
NO _x	Gas	8,760	0.20 lb/MMBtu			236.9	1,037.6	40 CFR 60.44(a)(1)	III.D.8.
NO _x	Oil	8,760	0.30 lb/MMBtu			355.4	1,556.4	40 CFR 60.44(a)(2)	III.D.8.

Notes:
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Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
PM	Coal	8,760	0.044 lb/MMBtu			160.2	701.5	PSD-FL-008(B)	III.E.5.
PM	Coal/Pet Coke	8,760	0.044 lb/MMBtu			160.2	701.5	PSD-FL-008(B)	III.E.5.
PM	Coal/RDF	8,760	0.050 lb/MMBtu			182.0	701.5	PSD-FL-008(B)	III.E.5.
PM	Coal/Pet Coke/RDF	8,760	0.050 lb/MMBtu			182.0	797.2	PSD-FL-008(B)	III.E.5.
PM	Oil	8,760	0.070 lb/MMBtu			254.8	1,116.0	PSD-FL-008(B)	III.E.5.
PM	Oil/RDF	8,760	0.075 lb/MMBtu			273.0	1,195.7	PSD-FL-008(B)	III.E.5.
VE	All	8,760	20% w/ 27% for 6 min/hr					40 CFR 60.42(a)(2)	III.E.5.
SO ₂	Oil	8,760	0.80 lb/MMBtu			2,912.0	12,754.6	40 CFR 60.43(a)(1)	III.E.6. & 10
SO ₂	Solid	8,760	1.2 lb/MMBtu			4,368.0	19,131.8	40 CFR 60.43(a)(2)	III.E.6.
NO _x	Gas	8,760	0.20 lb/MMBtu			728.0	3,188.6	40 CFR 60.44(a)(1)	III.E.13.
NO _x	Liquid	8,760	0.30 lb/MMBtu			1,092.0	4,783.0	40 CFR 60.44(a)(2)	III.E.13.
NO _x	Solid	8,760	0.70 lb/MMBtu			2,548.0	11,180.2	40 CFR 60.44(a)(3)	III.E.13.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

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Table 1-1, Summary of Air Pollutant Standards and Terms

Lakeland Electric & Water Utilities
 C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
 Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. Brief Description
 I-028] McIntosh Unit 5 - 250 MW Simple Cycle Stationary Combustion Turbine

Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions			Equivalent Emissions*		Regulatory Citation(s)	See permit condition(s)
			Standard(s)	lbs./hour	TPY	lbs./hour	TPY		
VE	All	8,760	10%					PSD-FL-245	III.F.19.
CO	Gas	8,760	25 ppm @15% O ₂	161.0			635.1	PSD-FL-245	III.F.16. & F.17.
CO	Oil	Fuel Total	90 ppm @15% O ₂	539.0			90.4	PSD-FL-245	III.F.16. & F.17.
NO _x	Gas	8,760	25 ppm @15% O ₂	262.0			1,038.0	PSD-FL-245	III.F.11. to F.15.
NO _x	Oil	Fuel Total	42 ppm @15% O ₂	413.0			69.3	PSD-FL-245	III.F.11. to F.15..
SO ₂	Gas	8,760		8.0	38.4			PSD-FL-245	III.F.18.
SO ₂	Oil	8,760	2.5% S by weight	7.2	Included above			PSD-FL-245	III.F.18.
VOC	Gas	8,760	4 ppmvd	11.0			43.8	PSD-FL-245	III.F.20.
VOC	Oil	8,760	10 ppmvd	25.0			18.5	PSD-FL-245	III.F.20.

Notes:

* The "Equivalent Emissions" listed are for informational purposes only.

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	Gas	DEP Method 9	Renewal	1-Jul	60 minutes		III.A.17. & 18. & 28.
VE	Oil	DEP Method 9	Annual	1-Jul	60 minutes		III.A.17. & 18. & 28.
PM	Gas	EPA Method 17, 5, 5B, or 5F	ASP No. 97-B-01	1-Jul	1 hour		III.A.19. & 29.
PM	Oil	EPA Method 17, 5, 5B, or 5F	Annual	1-Jul	1 hour		III.A.19. & 29.
SO ₂	Oil	EPA Method 6, 6A, 6B, or 6C	Annual	1-Jul	1 hour		III.A.15. & 20. & 27.
SO ₂	Oil	2.5% S by weight	Each Delivery				III.A.15. & 20. & 21.
Arsenic	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
Cadmium	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
Chromium	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
Lead	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
Total Halogens	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
Flash Point	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.
PCBs	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.11. & 30. & 34.

Notes:

* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.

** CMS [=] continuous monitoring system

[electronic file name: 10500042.xls]

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
 C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS **	
							See permit condition(s)
VE SO ₂	All Oil	EPA Method 9 0.5% S by weight	Annual Each Delivery	9-Jun	30 minutes		III.B.11. III.B.6. & 9. & 12.

Notes:
 * The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
 **CMS | =| continuous monitoring system

[electronic file name: 10500042.xls]

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
 C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description**
 [004] Gas Turbine Peaking Unit 1

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS **	See permit condition(s)
VE	Oil	EPA Method 9	Annual	1-Aug	30 minutes		III.B.11. & 15. & 16.
SO ₂	Oil	0.5% S by weight	Each Delivery				III.C.6. & 9. & 12.

Notes:
 * The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
 ** CMS [=] continuous monitoring system

[electronic file name: 10500042.xls]

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
PM	Oil	EPA Method 17, 5, or 5B	Annual	23-Jun	1 hour		III.D.15., 19., & 27.
VE	Gas	EPA Method 9	Renewal	23-Jun	60 minutes	Yes	III.D.15. & 26.
VE	Oil	EPA Method 9	Annual	23-Jun	60 minutes	Yes	III.D.15. & 26.
SO ₂	Oil	EPA Method 6, 6A, or 6C	Annual	23-Jun	1 hour	Yes	III.D.16., 17., 19., & 29.
NO _x	All	EPA Method 7, 7A, 7C, 7D, or 7E	Annual	23-Jun	1 hour		III.D.15. & 19.

Notes:
 * The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
 ** CMS [=] continuous monitoring system

[electronic file name: 10500042.xls]

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
 C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

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

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS **	
						CMS **	See permit condition(s)
PM	Gas Only	EPA Method 17, 5, or 5B	ASP No. 97-B-01	23-Jun	1 hour		III.E.21., 23., & 31.
PM	All Other	EPA Method 17, 5, or 5B	Annual	23-Jun	1 hour		III.E.21., 23., & 31.
VE	Gas Only	EPA Method 9	Renewal	23-Jun	60 minutes	Yes	III.D.21. & 30.
VE	All Other	EPA Method 9	Annual	23-Jun	60 minutes	Yes	III.D.21. & 30.
SO ₂	Liquid & Solid	EPA Method 6, 6A, or 6C	Annual	23-Jun	1 hour	Yes	III.E.21. & 23.
NO _x	All	EPA Method 7, 7A, 7C, 7D, or 7E.	Annual	23-Jun	1 hour	Yes	III.E.21. & 23.

Notes:
 * The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
 ** CMS [=] continuous monitoring system

[electronic file name: 10500042.xls]

Table 2-1, Summary of Compliance Requirements

Lakeland Electric & Water Utilities
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description**
[-028] McIntosh Unit 5 - 250 MW Simple Cycle Stationary Combustion Turbine

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS* *	See permit condition(s)
VE	All	EPA Method 9	Annual	30-Jan	60 minutes	Yes	III.F.34.
CO	All	EPA Method 10	Annual	30-Jan	60 minutes		III.F.34. & F.37.
NO _x	All	EPA Method 20	Annual	30-Jan	1 hour		III.F.34. & F.37.
SO ₂	Gas	EPA Method 20 & ASTM	Annual & Delivery	30-Jan	1 hour		III.F.34. & F.36.
SO ₂	Oil	EPA Method 20 & ASTM	Annual & Delivery	30-Jan	1 hour		III.F.34. & F.36.
VOC	All	EPA Methods 18 and/or 25A	Initial & Modification	Modification	1 hour		III.F.34. & F.38.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
** CMS [=] continuous monitoring system

[electronic file name: 10500042.xls]

Phase II Permit Application

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

This submission is: New Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

C.D. McIntosh, Jr., FL, 676

STEP 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

Compliance Plan				
a	b	c	d	e
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
1	Yes	No		
2	Yes	No		
3	Yes	No		
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

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

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit 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, 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 permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
- (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 permitting authority; 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.

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)) 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)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 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 Administrator or permitting authority:
 - (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;
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

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

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 a written 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 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, 75, 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 a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an 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.

Certification

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

Name *Timothy C. Eates, Plant Manager*

Signature *Timothy C. Eates*

Date *12/14/95*

STEP 5 (optional)
Enter the source AIRS
and FINDS identification
numbers, if known

AIRS
FINDS

Phase II Permit Application

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

This submission is: New Revised

STEP 1

Identify the source by plant name, State, and ORIS code from NADB

C. D. McIntosh, Jr. Plant Name	FL State	676 ORIS Code
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STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a Boiler ID#	Compliance Plan b c		d New Units	e New Units
	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	Commence Operation Date	Monitor Certification Deadline
5	Yes	No	1/1/99	3/1/99
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3

Check the box if the response in column c of Step 2 is "Yes for any unit

For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

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

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont)

certificate of representation changing the designated representative;

- (ii) All emissions monitoring information, in accordance with 40 CFR part 75;
- (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
- (iv) Copies of all documents used to complete an Acid Rain 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 a written 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 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, 75, 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.

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(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.

Certification

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

Name

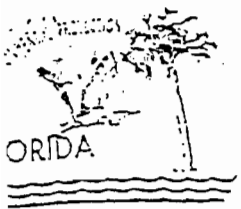
Timothy C. Bates, Power Production Manager

Signature <i>Timothy C Bates</i>	Date <i>3/9/98</i>
----------------------------------	--------------------

STEP 5 (optional)
Enter the source AIRS
and FINDS identification

AIRS
FINDS

BEST AVAILABLE COPY



Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia E. Wetherell
Secretary

July 9, 1997

Certified Mail - Return Receipt Requested

Mr. Rich Piper, Chair
Florida Power Coordinating Group, Inc.
405, Reo Street, Suite 100
Tampa, Florida 33609-1004

Dear Mr. Piper:

Enclosed is a copy of a Scrivener's Order correcting an error in the Order concerning particulate matter testing of natural gas fired boilers.

If you have any questions concerning the above, please call Yogesh Manocha at 904/488-6140, or write to me.

Sincerely,

M. D. Harley, P.E., DEE
P.E. Administrator
Emissions Monitoring Section
Bureau of Air Monitoring and
Mobile Sources

MDH:ym

cc: Dotty Diltz, FDEP
Pat Comer, FDEP

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:)

Florida Electric Power Coordinating Group, Inc.,)

ASP No. 97-B-01

Petitioner.)

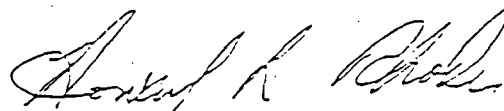
ORDER CORRECTING SCRIVENER'S ERROR

The Order which authorizes owners of natural gas fired fossil fuel steam generators to forgo particulate matter compliance testing on an annual basis and prior to renewal of an operation permit entered on the 17th day of March, 1997, is hereby corrected on page 4, paragraph number 4, by deleting the words "pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.":

4. In renewing an air operation permit ~~pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.~~, the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

DONE AND ORDERED this 2 day of July, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 10th day of July 1997.

Clerk Stamp

FILED AND ACKNOWLEDGMENT
FILED, on this date, pursuant to
§120.52(7), Florida Statutes, with the
designated Department Clerk, receipt of
which is hereby acknowledged.

Martha Jewell Wise 7/10/97
Clerk Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:)

Florida Electric Power Coordinating Group, Inc.,)

ASP No. 97-B-01

Petitioner.)

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), the Florida Electric Coordinating Group, Incorporated, (FCG) petitioned for approval to: (1) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test; and, (2) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test during the year prior to renewal of an operation permit. This Order is intended to clarify particulate testing requirements for those fossil fuel steam generators which primarily burn gaseous fuels including, but not necessarily limited to natural gas.

Having considered the provisions of Rule 62-296.405(1), F.A.C., Rule 62-297.310(7), F.A.C., and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS-OF FACT

1. The Florida Electric Power Coordinating Group, Incorporated, petitioned the Department to exempt those fossil fuel steam generators which have a heat input of more than 250 million Btu per hour and burn solid and/or liquid fuel less than 400 hours during the year from the requirement to conduct an annual particulate matter compliance test. [Exhibit 1]

2. Rule 62-296.405(1)(a), F.A.C., applies to those fossil fuel steam generators that are not subject to the federal standards of performance for new stationary sources (NSPS) in 40 CFR 60 and which have a heat input of more than 250 million Btu per hour.

3. Rule 62-296.405(1)(a), F.A.C., limits visible emissions from affected fossil fuel steam generators to, "20 percent opacity except for either one six-minute period per hour during which

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not exceed 40 percent. The option selected shall be specified in the emissions unit's construction and operation permits. Emissions units governed by this visible emission limit shall test for particulate emission compliance annually and as otherwise required by Rule 62-297, F.A.C."

4. Rule 62-296.405(1)(a), F.A.C., further states, "Emissions units electing to test for particulate matter emission compliance quarterly shall be allowed visible emissions of 40 percent opacity. The results of such tests shall be submitted to the Department. Upon demonstration that the particulate standard has been regularly complied with, the Secretary, upon petition by the applicant, shall reduce the frequency of particulate testing to no less than once annually."

5. Rule 297.310(7)(a)1., F.A.C., states, "The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit."

6. Rule 297.310(7)(a)2., F.A.C., states, "The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision."

7. Rule 297.310(7)(a)3., F.A.C., further states, "In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal: a. Did not operate; or, b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours."

8. Rule 297.310(7)(a)4., F.A.C., states, "During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for: a. Visible emissions, if there is an applicable standard; b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant...."

9. Rule 297.310(7)(a)5., F.A.C., states, "An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours."

10. Rule 297.310(7)(a)6., F.A.C., states, "For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be

required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup."

11. Rule 297.310(7)(a)7., F.A.C., states, "For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup." [Note: The reference should be to Rule 62-296.405(1)(a), F.A.C., rather than Rule 62-296.405(2)(a), F.A.C.]

12. The fifth edition of the U. S. Environmental Protection Agency's Compilation of Air Pollutant Emission Factors, AP-42, that emissions of filterable particulate from gas-fired fossil fuel steam generators with a heat input of more than about 10 million Btu per hour may be expected to range from 0.001 to 0.006 pound per million Btu. - [Exhibit 2]

13. Rule 62-296.405(1)(b), F.A.C. and the federal standards of performance for new stationary sources in 40 CFR-60.42, Subpart D, limit particulate emissions from uncontrolled fossil fuel fired steam generators with a heat input of more than 250 million Btu to 0.1 pound per million Btu.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider the matter pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Pursuant to Rule 62-297.310(7), F.A.C., the Department may require Petitioner to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

3. There is reason to believe that a fossil fuel steam generator which does not burn liquid and/or solid fuel (other than during startup) for a total of more than 400 hours in a federal fiscal year and complies with all other applicable limits and permit conditions is in compliance with the applicable particulate mass emission limiting standard.

ORDER

Having considered the requirements of Rule 62-296.405, F.A.C., Rule 62-297.310, F.A.C., and supporting documentation, it is hereby ordered that:

1. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours;

2. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup;

3. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(1)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup;

4. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

5. Pursuant to Rule 62-297.310(7), F.A.C., owners of affected fossil fuel steam generators may be required to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

6. Pursuant to Rule 62-297.310(8), F.A.C., owners of affected fossil fuel steam generators shall submit the compliance test report to the District Director of the Department district office having jurisdiction over the emissions unit and, where applicable, the Air Program Administrator of the appropriate Department-approved local air program within 45 days of completion of the test.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 of the Florida Statutes, or a party requests mediation as an alternative remedy under section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of

the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

- (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department File Number, and the county in which the project is proposed;
- (b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
- (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
- (d) A statement of the material facts disputed by each petitioner, if any;
- (e) A statement of facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action;
- (f) A statement identifying the rules or statutes each petitioner contends require reversal or modification of the Department's action or proposed action; and,
- (g) A statement of the relief sought by each petitioner, stating precisely the action each petitioner wants the Department to take with respect to the Department's action or proposed action in the notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information:

(a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any;

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

(d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following:

(a) The names, addresses, and telephone numbers of any persons who may attend the mediation;

(b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

(c) The agreed allocation of the costs and fees associated with the mediation;

(d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

(e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

(f) The name of each party's representative who shall have authority to settle or recommend settlement; and

(g) The signatures of all parties or their authorized representatives.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will

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specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542 of the Florida Statutes. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

The petition must specify the following information:

- (a) The name, address, and telephone number of the petitioner;
- (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;
- (c) Each rule or portion of a rule from which a variance or waiver is requested;
- (d) The citation to the statute underlying (implemented by) the rule identified in (c) above;
- (e) The type of action requested;
- (f) The specific facts that would justify a variance or waiver for the petitioner;
- (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and
- (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver, when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully

each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

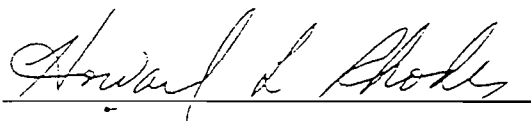
This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 17 day of March, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 18th day of March 1997.

Clerk Stamp

FILED AND ACKNOWLEDGMENT
FILED, on this date, pursuant to
§120.52(7), Florida Statutes, with the
designated Department Clerk, receipt of
which is hereby acknowledged.

Martha M. Wise 3-18-97
Clerk Date



January 28, 1997

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32301

RECEIVED

JAN 28 1997

BUREAU OF
AIR REGULATION

RE: Comments Regarding Draft Title V Permits

Dear Mr. Fancy:

The Florida Electric Power Coordinating Group, Inc. (FCG), which is made up of 36 utilities owned by investors, municipalities, and cooperatives, has been following the implementation of Title V in Florida and recently submitted comments to you on draft Title V permit conditions by letter dated December 4, 1996. As indicated in that letter, representatives from the FCG would like to meet with you and other members of your air permitting staff to discuss some significant concerns that FCG member companies have regarding conditions that may be included in Title V permits issued by your office. While we will be discussing these issues with you and your staff in greater detail at that meeting, we would like to explain some of our concerns in this letter.

Primarily, the FCG members are concerned that the Title V permits may contain conditions that are much different in important respects than those conditions currently included in existing air permits. During the rulemaking workshops and seminars conducted by the Department to discuss the rules implementing the Title V permitting program, representations were made on several occasions that industry could expect to see permit conditions that were substantively similar to existing permit conditions and that primarily the format was changing. Representations were also made to industry that Title V did not impose additional substantive requirements beyond what was already required under the Department's rules. Based on the first draft Title V permit that we have reviewed, we are concerned that there may be some attempt to change the substantive requirements on existing facilities through the Title V permitting process, and we would like to discuss this with you at the meeting we have scheduled for January 30, 1997.

1. Federal Enforceability--The FCG has long been concerned about the designation of non-federally enforceable permit terms and conditions. We are concerned about this issue because the Department's first draft Title V permits have included language stating that *all* terms and conditions would become federally enforceable once the permit is issued. This approach is consistent with the Department's guidance memorandum dated September 13, 1996 (DARM-PER/V-18), but we understand that the Department may now intend to remove all references to

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
January 28, 1997
Page 2

the federal enforceability of permit terms and conditions. We are also concerned about this approach because a Title V permit is generally federally enforceable and, without any designation of non-federally enforceable terms and conditions, the entire permit could be interpreted to be federally enforceable. As we stated in the December 4 letter as well as our letter dated October 11, 1996, all terms and conditions in a Title V permit do *not* become enforceable by the U.S. Environmental Protection Agency and citizens under the Clean Air Act simply by inclusion in a Title V permit. To make it clear which provisions in a Title V permit are not federally enforceable (which are being included because of state or local requirements only), it is very important to specifically designate those conditions as having no federally enforceable basis. Such a designation is actually required under the federal Title V rules, which provide that permitting agencies are to "specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements." 40 CFR § 70.6(b). We would like to discuss with you our concerns about this issue and to again specifically request that when Title V permits are issued by the Department, conditions having no federally enforceable basis clearly be identified as such.

2. PM Testing on Gas--The FCG understands that the Department may attempt to require annual particulate matter compliance testing while firing natural gas to determine compliance with the 0.1 lb/mmBtu emission limit established under Rule 62-296.405(1)(b), F.A.C. The FCG member companies feel strongly that compliance testing for particulate matter should not be required while firing natural gas. The Department has not historically required particulate matter compliance testing while firing natural gas, it is not required under the current permits for these units, and it should not be necessary since natural gas is such a clean fuel. Typically only *de minimis* amounts of particulate matter would be expected from the firing of natural gas, so compliance testing would not provide meaningful information to the Department, and the expense to conduct such tests is not justified. We understand that Department representatives suggested that industry could pursue an alternative test procedure under Rule 62-297.620, F.A.C., to allow a visible emissions test to be used in lieu of a stack test for determining compliance with the particulate matter limit. While certainly a visible emissions test would be preferable over a stack test, neither of these tests should be needed to demonstrate compliance with the particulate matter limit of 0.1 lb/mmBtu while burning natural gas. The FCG strongly urges that the Department reconsider its position on this issue and clarify that compliance testing for particulate matter while firing natural gas is not required.

3. Excess Emissions--By letter dated December 5, 1996, the U.S. Environmental Protection Agency (EPA) submitted a letter commenting on a draft Title V permit that had been issued by the Department and indicated some concern regarding excess emission provisions included in conditions that were quoted from Rule 62-210.700, F.A.C. Because the permit conditions cited simply quote the applicable provisions of the Department's rules regarding

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
January 28, 1997
Page 3

excess emissions and because these rules have been approved as part of Florida's State Implementation Plan, the permit conditions are appropriate to be included in the permit. We understand that the Department intends to include as applicable requirements in Title V permit conditions the provisions of Rule 62-210.700, F.A.C. If the Department receives any further adverse comments regarding the excess emissions rule under 62-210.700, F.A.C., we would appreciate your contacting us. Because this issue is so important to us, we would like to discuss it with you in greater detail at our meeting on January 30.

4. Compliance Testing for Combustion Turbines--While the Department's November 22, 1995, guidance regarding the compliance testing requirements for combustion turbines clearly states that the use of heat input curves based on ambient temperatures and humidities is to be included as a permit condition *only* if requested by a permittee, we understand that the Department may intend to include this requirement in Title V permits for all combustion turbines. As we are sure you recall, the FCG worked over a period of several months with the Department on the development of the guidance memorandum and it was clearly understood by FCG members that the heat input curves would not be mandated but would remain voluntary for any existing combustion turbine. It was also understood by FCG members that the requirement to conduct testing at 95 to 100 percent of capacity would be required only if the permit applicant requested the use of heat input curves. We understand that the Department may be interpreting the requirement to use heat input curves and to test at 95 to 100 percent of permitted capacity to be mandatory for all combustion turbines. We would like to clarify this with you during our meeting. Also, we would like to confirm that, regardless of whether a combustion turbine uses heat input curves or tests at 95 to 100 percent of permitted capacity, it is necessary to test at four load points and correct to ISO *only* to determine compliance with the nitrogen oxides (NOx) standard under New Source Performance Standard Subpart GG under 40 CFR § 60.332 and not annually thereafter.

5. Test Methods--The FCG is concerned about the possibility of the Department requiring a full permit revision to authorize the use of an approved test method not specifically identified in a Title V permit, even though the Department may have separately approved the use of the particular test method for a unit (i.e., through a compliance test protocol). It is the FCG's position that language should be included in all Title V permits indicating that other test methods approved by the Department may be used. Further, a full permit revision (including public notice) should *not* be necessary when a test method not previously identified in the permit is approved for use by a unit. The Department's subsequent approval of test methods should simply be included in the next permit renewal cycle. The FCG understands that the Department planned to confirm this approach with the U.S. Environmental Protection Agency Region IV, and we would like to discuss this issue with you at the January 30 meeting to learn of the agency's response.

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
January 28, 1997
Page 4

6. Quarterly Reports--The FCG understands that the Department may be interpreting the quarterly reporting requirements under Rule 62-296.405(1)(g), F.A.C., to apply regardless of whether continuous emissions monitors were required under the preceding Rule 62-296.405(1)(f), F.A.C. It is the FCG's position that quarterly reports are required under Rule 62-296.405(1)(g) only when continuous emissions monitors are required under the preceding paragraph (f). While this may not be entirely clear from the language of the rules, paragraphs (f) and (g) were originally included in a separate rule on "continuous emission monitoring requirements" where it was very clear that the requirements of paragraph (g) applied *only* if continuous emission monitoring was required under paragraph (f). Research indicates that Rule 17-2.710, F.A.C. (copy attached), where these provisions were originally located, was first transferred to Rule 17-297.500, F.A.C. (which later became Rule 62-297.500), later repealed in November of 1994 and ultimately replaced with what is now Rule 62-296.405(1)(f) and (g), F.A.C. To the extent that an emissions unit is not subject to Rule 62-296.405(1)(f) and is not required to install and operate continuous emissions monitors (e.g., oil- and gas-fired units), the quarterly reporting requirements of paragraph (g) should not apply.

7. Trivial Activities--As you may recall, in May of 1996, the FCG submitted to the Department a list of small, *de minimis* emissions units and activities that it considered to be "trivial," consistent with the list developed by EPA as part of the Title V "White Paper" and incorporated by reference by the Department in its March 15, 1996, guidance memorandum (DARM-PER/V-15-Revised). We never received a response from the Department and now understand that the Department may not have made a determination as to whether any of the emission units or activities on the list should qualify as "trivial." This is an important issue to the FCG because only "trivial" activities can be omitted from the Title V permit application and permit, and ultimately omitted from emission estimates in the annual air operation reports under Rule 62-210.370(3), F.A.C. The FCG remains hopeful that the Department will consider its request to determine that most, if not all, of the emission units and activities on the May, 1996, list to be "trivial." We would like to discuss a possible resolution of this issue with you and your staff at the January 30 meeting.

8. Permit Shield--The FCG continues to be concerned about the language in Conditions 5 and 20 of Appendix TV-1, Title V Conditions, which circumvents the permit shield provisions under Section 403.0872(15), Florida Statutes, and Rule 62-213.460, F.A.C. The FCG believes that these conditions should be deleted in their entirety. To the extent that the Department attempt to caveat the applicability of those conditions, the FCG believes that it is important to cite to not only the regulatory citation for the permit shield but the statutory citation as well.

Thank you again for considering the FCG's comments on the draft Title V permits. We very much appreciate the cooperation we have received from the Department throughout the

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
January 28, 1997
Page 5

Title V implementation process, and we look forward to our meeting later this week. If you have any questions in the meantime, please call me at 561-625-7661.

Sincerely,

Rich Piper

Rich Piper, Chair *hgm*
FCG Air Subcommittee

Enclosures

cc: Howard L. Rhodes, DEP
John Brown, DEP
Pat Comer, DEP OGC
Scott M. Sheplak, DEP
Edward Svec, DEP
FCG Air Subcommittee
Angela Morrison, HGSS

AP-42
FIFTH EDITION
JANUARY 1995

COMPILATION
OF
AIR POLLUTANT
EMISSION FACTORS

VOLUME I:
STATIONARY POINT
AND AREA SOURCES

Office Of Air Quality Planning And Standards
Office Of Air And Radiation
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

January 1995

Exhibit 2

1.4 Natural Gas Combustion

1.4.1 General¹⁻²

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Section 5.3, Natural Gas Processing). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9800 kcal scm (900 to 1100 Btu/scf).

1.4.2 Emissions And Controls³⁻⁵

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e. g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas

recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensable fractions, based on the EPA sampling method. Filterable and condensable emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensable material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, and 1.4-3.⁶ For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

Table 1.4-1 (Metric And English Units) EMISSION FACTORS FOR PARTICULATE MATTER (PM)
FROM NATURAL GAS COMBUSTION^a

Combustor Type (Size, 10 ⁶ Btu/hr Heat Input) (SCC) ^b	Filterable PM ^c			Condensable PM ^d		
	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	16 - 80	1 - 5	B	ND	ND	NA
Small industrial boilers (10 - 100) (1-02-006-02)	99	6.2	B	120	7.5	D
Commercial boilers (0.3 - < 10) (1-03-006-03)	72	4.5	C	120	7.5	C
Residential furnaces (< 0.3) (No SCC)	2.8	0.18	C	180	11	D

^a References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10⁶ cubic meters natural gas fired and lb of pollutant/10⁶ cubic feet natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

^b SCC = Source Classification Code.

^c Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

^d Condensable PM is that particulate matter collected using EPA Method 202, (or equivalent). Total PM is the sum of the filterable PM and condensable PM. All PM emissions can be assumed to be less than 10 micrometers in aerodynamic equivalent diameter (PM-10).

Table 1.4-2 (Metric And English Units). EMISSION FACTORS FOR SULFUR DIOXIDE (SO₂), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION^a

Combustor Type (Size, 10 ⁶ Btu/hr Heat Input) (SCC) ^b	SO ₂ ^c			NO _x ^d			CO ^e		
	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING
Utility/Large Industrial Boilers (> 100) (1-01-006-01, 1-01-006-04)									
Uncontrolled	9.6	0.6	A	8800	550 ^f	A	640	40	A
Controlled - Low NO _x burners	9.6	0.6	A	1300	81 ^f	D	ND	ND	NA
Controlled - Flue gas recirculation	9.6	0.6	A	850	53 ^f	D	ND	ND	NA
Small Industrial Boilers (10 - 100) (1-02-006-02)									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO _x burners	9.6	0.6	A	1300	81 ^f	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3 - < 10) (1-03-006-03)									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO _x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	ND	ND	NA
Residential Furnaces (< 0.3) (No SCC)									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

^a Units are kg of pollutant/10⁶ cubic meters natural gas fired and lb of pollutant/10⁶ cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

^b SCC = Source Classification Code.

^c Reference 7. Based on average sulfur content of natural gas, 4600 g/10⁶ Nm³ (2000 gr/10⁶ scf).

Table 1.4-2 (cont.).

- ^d References 10,15-19. Expressed as NO₂. For tangentially fired units, use 4400 kg/10⁶ m³ (275 lb/10⁶ ft³). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO_x emissions from controlled boilers will be reduced at low load conditions.
- ^e References 9-10,16-18,20-21.
- ^f Emission factors apply to packaged boilers only.

Table 1.4-3 (Metric And English Units). EMISSION FACTORS FOR CARBON DIOXIDE (CO₂) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION^a

Combustor Type (Size, 10 ⁶ Btu/hr Heat Input) (SCC) ^b	CO ₂ ^c			TOC ^d		
	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	ND ^e	ND	NA	28 ^f	1.7 ^f	C
Small industrial boilers (10 - 100) (1-02-006-02)	1.9 E+06	1.2 E+05	D	92 ^g	5.8 ^g	C
Commercial boilers (0.3 - < 10) (1-03-006-03)	1.9 E+06	1.2 E+05	C	128 ^h	8.0 ^h	C
Residential furnaces (No SCC)	2.0 E+06	1.3 E+05	D	180 ^h	11 ^h	D

^a All factors represent uncontrolled emissions. Units are kg of pollutant/10⁶ cubic meters and lb of pollutant/10⁶ cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given factor by the ratio of the specified heating value to this average heating value. NA = not applicable.

^b SCC = Source Classification Code.

^c References 10,22-23.

^d References 9-10,18.

^e ND = no data.

^f Reference 8: methane comprises 17% of organic compounds.

^g Reference 8: methane comprises 52% of organic compounds.

^h Reference 8: methane comprises 34% of organic compounds.

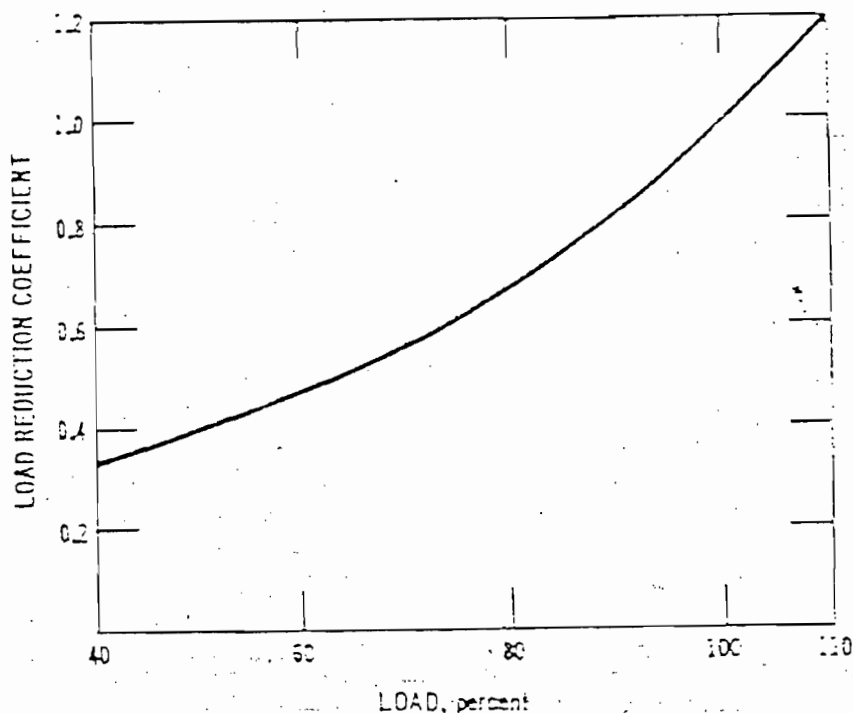


Figure 1.4-1. Load reduction coefficient as a function of boiler load.
(Used to determine NO_x reductions at reduced loads in large boilers.)

References For Section 1.4

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10. *Field Investigation of Emissions From Combustion Equipment for Space Heating*, EPA-R2-73-084a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.
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17. *Source Test For Measurement of Nitrogen Oxides and Carbon Monoxide Emissions From Boiler Exhaust at GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.
18. J. P. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.
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20. *Background Information Document For Small Steam Generating Units*, EPA-450/T-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.
21. *Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503*, American Gas Association Laboratories, Cleveland, OH, May 1971.
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23. Private communication from Kim Black (Industrial Combustion) to Ralph Harris (MR), Independent Third Party Source Tests, February 7, 1992.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:)
)
Florida Electric Power Coordinating Group, Inc.,) ASP No. 97-B-01
)
Petitioner.)

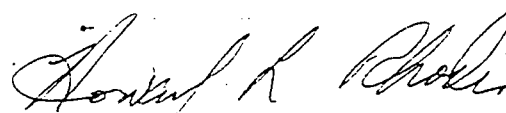
ORDER CORRECTING SCRIVENER'S ERROR

The Order which authorizes owners of natural gas fired fossil fuel steam generators to forgo particulate matter compliance testing on an annual basis and prior to renewal of an operation permit entered on the 17th day of March, 1997, is hereby corrected on page 4, paragraph number 4, by deleting the words "pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.":

4. In renewing an air operation permit pursuant to Rule ~~62-210.300(2)(a)3.b., c., or d., F.A.C.~~, the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

DONE AND ORDERED this 2 day of July, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

40 CFR 60 Subpart A-General Provisions
(Version dated 07/23/97)

These conditions are based on the July 1996 CFR version.

[Applicability note: These conditions are for an NSPS emissions unit (a.k.a. "federal facility") that has been built and has conducted the initial performance test(s) in accordance with 40 CFR 60.8.]

{Note: Rule 62-204.800(d), F.A.C., did not adopt/incorporate 40 CFR 60.4, 40 CFR 60.16, and 40 CFR 60.17.}

1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.

[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

40 CFR 60.7 Notification and record keeping.

2. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

3. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 CFR 60.7(b)]

4. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate).

Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1), (2), (3), and (4)]

5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)

[40 CFR 60.7(d)(1) and (2)]

6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After

demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

7. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.

[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

40 CFR 60.8 Performance tests.

8. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

40 CFR 60.11 Compliance with standards and maintenance requirements.

9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

[40 CFR 60.11(a)]

10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).

[40 CFR 60.11(b)]

11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

[40 CFR 60.11(c)]

12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR 60.11(d)]

13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the

Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.

[40 CFR 60.11(e)(5)]

40 CFR 60.12 Circumvention.

14. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

[40 CFR 60.13(a)]

16. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.

[40 CFR 60.13(c)(1)]

17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

[40 CFR 60.13(d)(1) and (2)]

18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)(1) and (2)]

19. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.

[40 CFR 60.13(f)]

20. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

[40 CFR 60.13(g)]

21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally

spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O₂ or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

[electronic file name: 40CFR60a.doc]



December 4, 1997

Mr. Scott M. Sheplak, P.E.
Administrator, Title V Section
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Phase II NO_x Compliance Plans

Dear Scott:

We are in receipt of your communication dated November 10, 1997 in reference to the above. We are baffled as whether or not it is necessary for us to complete the phase II NO_x Compliance Plan as on 12/16/96 we submitted to EPA such form in connection to the "early election" program. From the enclosed documents you will note EPA's acceptance of our participation.

Although we feel this may be unnecessary, nonetheless, to aid you in your recording of such data we have completed the form you have sent to us and we are enclosing same herewith.

If you should have any questions, please do not hesitate to contact me at (941) 499-6603.

Sincerely

Farzie Shelton
Manager of Environmental Permitting & Compliance
Production Division

Enc.

RECEIVED

DEC 09 1997

BUREAU OF
AIR REGULATION

Florida Department of Environmental Protection

Phase II NO_x Compliance Plan

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

This submission is: New Revised Page of

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Plant Name C.D. McIntosh Power Plant	State FL	ORIS Code 000676
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" 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#	ID#	ID#	ID#	ID#	ID#
1050004					
Type	Type	Type	Type	Type	Type
DBW					
0.51b/mmbtu					

- | | | | | | | |
|---|-------------------------------------|--------------------------|--------------------------|--------------------------|--------------------------|--------------------------|
| (a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan) | <input checked="" type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (g) Standard annual average emission limitation of 0.66 lb/mmBtu (for cyclone boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (j) NO _x Averaging Plan (include NO _x Averaging form) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |
| (k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack) | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> | <input type="checkbox"/> |

Plant Name (from Step 1) C.D. McIntosh Power Plant

STEP 2, cont'd.

ID#	ID#	ID#	ID#	ID#	ID#
Type	Type	Type	Type	Type	Type

(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)

<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
--------------------------	--------------------------	--------------------------	--------------------------	--------------------------	--------------------------

(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)

<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
--------------------------	--------------------------	--------------------------	--------------------------	--------------------------	--------------------------

(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)

<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
--------------------------	--------------------------	--------------------------	--------------------------	--------------------------	--------------------------

(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing

<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
--------------------------	--------------------------	--------------------------	--------------------------	--------------------------	--------------------------

(p) Repowering extension plan approved or under review

<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
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STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an 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)(iii).

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, 2000, 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, 2003 or January 1 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 after the year for which there is a failure to demonstrate compliance, and the designated representative may not 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 representative 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 1 boilers 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.

STEP 3, cont'd.

Certification

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

Name Ronald W. Tomlin	
Signature <i>Ronald W. Tomlin</i>	Date 12-01-97



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 4

ATLANTA FEDERAL CENTER
100 ALABAMA STREET, S.W.
ATLANTA, GEORGIA 30303-3104

APR 07 1997

4APT-ARB

Mr. Ronald W. Tomlin
Designated Representative
City of Lakeland
Electric and Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5050

RECEIVED

APR 11 1997

RONALD W. TOMLIN
ASST. MANAGING DIR.

Dear Mr. Tomlin:

Enclosed you will find the draft Phase I Acid Rain permit issued by the U.S. Environmental Protection Agency on March 27, 1997, for the affected sources in your nitrogen oxides early election compliance plan. This permitting action will become final 40 days after a notice is published in the Federal Register or local newspaper, whichever is later, unless adverse comment is received within 30 days after publication. Notice of this permitting action is scheduled for publication on April 11, 1997.

Your cooperation has been appreciated. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 562-9127.

Sincerely,

R. Douglas Neeley

for Chief

Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

Enclosure

cc: Tom Cascio, Florida DEP



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
100 ALABAMA STREET, S.W.
ATLANTA, GEORGIA 30303-3104

PHASE I ACID RAIN PERMIT For NO_x Early Election

Issued to: C.D. McIntosh Power Plant
Operated by: City of Lakeland
Effective: January 1, 1997 through December 31, 1999

This page will be replaced to document new EPA actions each time a new action is taken by the Agency. This is the initial permitting action:

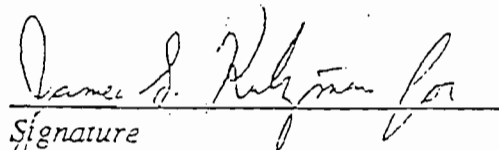
Summary of Previous Actions

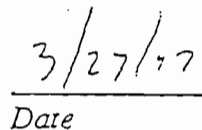
None.

Present Action

1. Permit, including the NO_x early election compliance plan, issued as a direct final permit for Unit 3. This action will become final 40 days after notice in the Federal Register or local newspaper, whichever is later, unless adverse comment is received within 30 days after publication.

(See page 1)


Signature


Date

Winston A. Smith
Director, Air, Pesticides and Toxics Management Division
U.S. Environmental Protection Agency, Region 4

61 Forsyth Street, S.W.

Atlanta, Georgia 30303

Telephone: (404) 562-9077

Facsimile: (404) 562-9095



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
100 ALABAMA STREET, S.W.
ATLANTA, GEORGIA 30303-3104

PHASE I ACID RAIN PERMIT For NO_x Early Election

Issued to: C.D. McIntosh Power Plant
Operated by: City of Lakeland
Effective: January 1, 1997 through December 31, 1999

The Acid Rain Permit comprises the following:

1. The statement of basis containing:

Part A, with references to statutory and regulatory authorities, and comments, notes and justifications that apply to the source in general; and

Part B, for each Early Election unit at this source:

- a NO_x compliance plan; and,
- comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements.

2. The permit application forms that this source submitted, as corrected by EPA. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

Plant Name: C.D. McIntosh Power Plant
State: Florida
ORIS Code: 0676

Statutory and Regulatory Authorities. In accordance with Title IV of the Clean Air Act Amendments of 1990, the U. S. Environmental Protection Agency issues this permit pursuant to 40 CFR part 72, subparts E and F, and part 76.

For further information contact:

Scott Davis, Acid Rain Contact
U.S. EPA, Region 4
Air, Pesticides and Toxics Management Division
Telephone: (404) 562-9127
Facsimile: (404) 562-9095

Comments, notes and justifications that apply to the source in general:

None.

R. SCOTT DAVIS

Permit Reviewer



Signature

3/24/97

Date

Plant Name: C.D. McIntosh Power Plant

State: Florida

ORIS Code: 0676

Boiler ID#: 3

NO_x Compliance Plan

EPA approves a nitrogen oxides early election plan for this unit for 1997-2007 under which this unit's annual average NO_x emission rate for each year, determined using the methods and procedures specified in 40 CFR part 75, shall not exceed the applicable emission limitation under 40 CFR 76.5(a), of 0.50 lbs/mmBtu for dry bottom wall-fired units. If this unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to any revised NO_x emission limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act, until January 1, 2008.

Comments, notes and justifications regarding permit decisions, and changes made to the permit application forms during the review process:

None.

R. SCOTT DAVIS

Permit Reviewer

R. Scott Davis

Signature

3/24/97

Date

For further information and a detailed description of the permits and permit modifications, see the information provided in the notice of permits and permit modifications elsewhere in today's Federal Register.

Dated: April 10, 1997.

Brian J. McLean,

Director, Acid Rain Division, Office of Atmospheric Programs, Office of Air and Radiation.

[FR Doc. 97-9865 Filed 4-15-97; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[FRL-5812-5]

Acid Rain Program: Permit and Permit Modifications

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of permits and permit modifications.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is issuing, as a direct final action, Phase I Acid Rain permits and permit modifications including nitrogen oxides (NO_x) compliance plans in accordance with the Acid Rain Program regulations (40 CFR parts 72 and 76). Because the Agency does not anticipate receiving adverse comments, the exemptions are being issued as a direct final action.

DATES: The permits and permit modifications issued in this direct final action will be final on May 26, 1997 or 40 days after publication of a similar notice in a local publication, whichever is later, unless significant, adverse comments are received by May 16, 1997 or 30 days after publication of a similar notice in a local publication, whichever is later. If significant, adverse comments are timely received on any permit or permit modification in this direct final action, that permit or permit modification will be withdrawn through a notice in the Federal Register.

ADDRESSES: *Administrative Records.* The administrative record for the permits, except information protected as confidential, may be viewed during normal operating hours at the following locations: for plants in New York, EPA Region 2, 290 Broadway, New York, NY, 10007-1866; for plants in Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina and Tennessee, EPA Region 4, 100 Alabama St., NW, Atlanta, GA, 30303; for plants in Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin, EPA Region 5, 77 West Jackson Blvd., Chicago, IL, 60604;

for plants in Colorado, Montana, North Dakota, Utah and Wyoming, EPA Region 8, 999 18th St., Denver, CO, 80202.

Comments. Send comments, requests for public hearings, and requests to receive notice of future actions to: for plants in New York, EPA Region 2, Division of Environmental Planning & Protection, Attn: Gerry DeGaetano (address above); for plants in Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina and Tennessee, EPA Region 4, Air, Pesticides and Toxics Management Division, Attn: Scott Davis (address above); for plants in Illinois, Indiana, and Ohio, EPA Region 5, Air and Radiation Division, Attn: Cecilia Mijares (address above); for plants in Michigan, Minnesota, and Wisconsin, EPA Region 5, Air and Radiation Division, Attn: Beth Valenziano (address above); for plants in Colorado, Montana, North Dakota, Utah and Wyoming, EPA Region 8, Air and Toxics Division, Attn: Mike Owens (address above). Submit comments in duplicate and identify the permit to which the comments apply, the commenter's name, address, and telephone number, and the commenter's interest in the matter and affiliation, if any, to the owners and operators of all units in the plan. All timely comments will be considered, except those pertaining to standard provisions under 40 CFR 72.9 or issues not relevant to the permit or the permit modification.

Hearings. To request a public hearing, state the issues proposed to be raised in the hearing. EPA may schedule a hearing if EPA finds that it will contribute to the decision-making process by clarifying significant issues affecting a NO_x compliance plan.

FOR FURTHER INFORMATION CONTACT: For plants in New York, call Gerry DeGaetano, 212-637-4020; for plants in Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina and Tennessee, call Scott Davis, 404-562-9127; for plants in Illinois, Indiana, and Ohio, call Cecilia Mijares, 312-886-0958; for plants in Michigan, Minnesota, and Wisconsin, call Beth Valenziano, 312-886-2703; for plants in Colorado, Montana, North Dakota, Utah and Wyoming, call Mike Owens, 303-312-6440.

SUPPLEMENTARY INFORMATION: Title IV of the Clean Air Act directs EPA to establish a program to reduce the adverse effects of acidic deposition by promulgating rules and issuing permits to emission sources subject to the program. In today's action, EPA is issuing permits and permit modifications that include approval of early election plans for NO_x. The units

that are included in the early election plans will be required to meet an actual annual average emissions rate for NO_x of either 0.45 lbs/MMBtu for tangentially-fired boilers or 0.50 lbs/MMBtu for dry bottom wall-fired boilers beginning on January 1, 1997 through December 31, 2007, after which they will be required to meet the applicable emissions limitation under 40 CFR 76.7(a) of 0.40 lbs/MMBtu for tangentially-fired boilers or 0.46 lbs/MMBtu for dry bottom wall-fired boilers. The following is a list of units included in the permits or permit modifications and the limits that they are required to meet:

S A Carlson units 9, 10, 11, and 12 in New York: 0.50 lbs/MMBtu. The designated representative is R. James Gronquist.

Kintigh unit 1 in New York: 0.50 lbs/MMBtu. The designated representative is James Rettberg.

Charles R Lowman units 2 and 3 in Alabama: 0.50 lbs/MMBtu. The designated representative is John Howard.

C D McIntosh unit 3 in Florida: 0.50 lbs/MMBtu. The designated representative is Ronald Tomlin.

Crystal River units 2, 4, and 5 in Florida: 0.45 lbs/MMBtu for unit 2; 0.50 lbs/MMBtu for units 4 and 5. The designated representative is W. Jeffrey Pardue.

Deerhaven unit B2 in Florida: 0.50 lbs/MMBtu. The designated representative is John Hancock, Jr.

St. Johns River Power Park units 1 and 2 in Florida: 0.50 lbs/MMBtu. The designated representative is Brian Wirz.

Scherer unit 4 in Georgia: 0.45 lbs/MMBtu. The designated representative is R. Haubein, Jr.

D B Wilson unit W1 in Kentucky: 0.50 lbs/MMBtu. The designated representative is Gregory Black.

Cane Run units 4, 5, and 6 in Kentucky: 0.50 lbs/MMBtu for units 4 and 5; 0.45 lbs/MMBtu for unit 6. The designated representative is Chris Herman.

Mill Creek units 1, 2, 3, and 4 in Kentucky: 0.45 lbs/MMBtu for units 1 and 2; 0.50 lbs/MMBtu for units 3 and 4. The designated representative is Chris Herman.

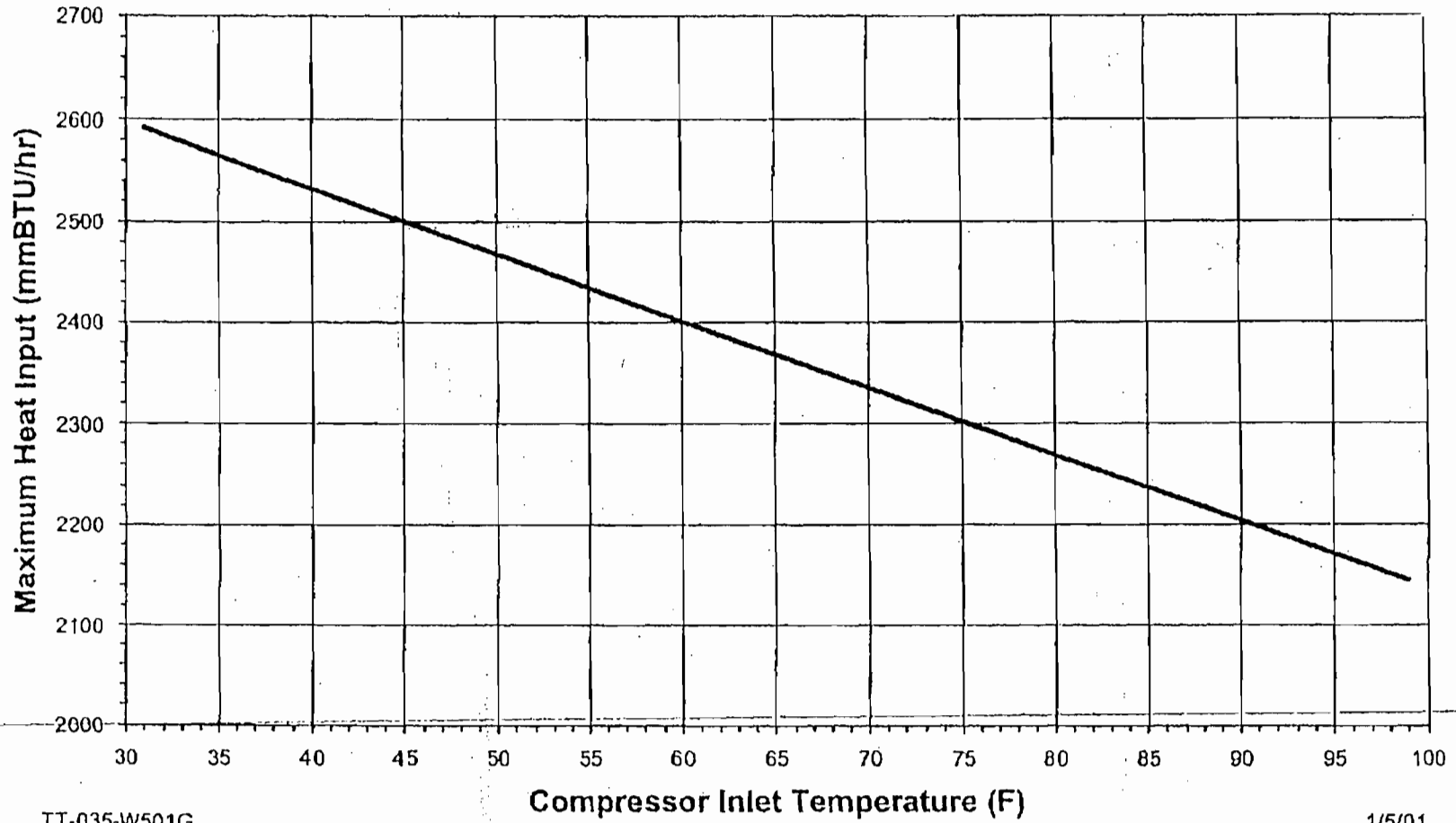
Trimble County unit 1 in Kentucky: 0.45 lbs/MMBtu. The designated representative is Chris Herman.

Buck units 5, 6, 7, 8, and 9 in North Carolina: 0.45 lbs/MMBtu. The designated representative is T. McMeekin.

Cliffside units 1, 2, 3, 4, and 5 in North Carolina: 0.45 lbs/MMBtu. The

For Your Information
Angela R. Morrison

W501G McIntosh #5, Lakeland, FL Maximum Heat Input as a Function of Compressor Inlet Temperature



TT-035-W501G

1/5/01

Appendix H-1: Permit History

Lakeland Electric
C. D. McIntosh, Jr. Power Plant

DRAFT Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type ¹
-001	Boiler Unit #1	AO53-243945	03/23/95	05/27/99	Operating
-002	Peaking Unit 2 (Diesel Engine)	AO53-244726	06/01/94	05/27/99	Operating
-003	Peaking Unit 3 (Diesel Engine)	AO53-244726	06/01/94	05/27/99	Operating
-004	Gas Turbine Peaking Unit 1	AO53-244727	06/01/94	05/27/99	Operating
-005	Unit 2 Electric Generator	AO53-174090	04/17/90	04/13/95	Operating
-006	McIntosh Unit 3 Coal/MSW Fired	PSD-FL-008 PSD-FL-008A PSD-FL-008B PA74-06SR	12/27/78 12/11/95 12/07/78		Construction(new)
-028	McIntosh Unit 5	PSD-FL-245	07/10/98	06/30/02	Construction(new)
-029	1.05 MM gal. storage tank	PSD-FL-245C 1050004-009-AV 1050004-011-AV	 11/19/00	06/30/02 12/31/03 12/31/03	Construction(mod) Title V Revision Title V Revision
ALL	C. D. McIntosh, Jr. Power Plant	1050004-003-AV	04/15/98	12/31/03	Initial Title V

¹ Project Type (select one): Title V: Initial, Revision, Renewal, or Admin. Correction; Construction (new or mod.); or, Extension (AC only).