MEMORANDUM

TO: Scott M. Sheplak, P.E.

FROM: Tom Cascio

THROUGH: Bruce Mitchell

DATE: September 22, 1999

Re: PROPOSED Permit Determination and
PROPOSED Title V Permit No. 0010006-001-AV
Gainesville Regional Utilities
Deerhaven Generating Station

This permit is for the initial Title V air operation permit for the subject facility.

The Revised DRAFT Title V Permit was rewritten based on comments made in two letters from the Gainesville Regional Utilities, and follow-up conversations with Yolanta Jonynas. I believe all concerns have been satisfactorily addressed, and recommend that the PROPOSED Permit Determination and PROPOSED Title V Permit be sent out as attached.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PROPOSED Permit Electronic Posting Courtesy Notification

City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station
Facility ID No.: 0010006
Alachua County

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0010006-001-AV

The electronic version of the PROPOSED permit was posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review on September 29, 1999.

USEPA's review period ends on the 45th day after the permit posting date. Day 45 is November 13, 1999 If an objection (veto) is received from USEPA, the permitting authority will provide a copy of the objection to the applicant.

Provided an objection is not received from USEPA, the PROPOSED permit will become a FINAL permit by operation of law on the 55th day after the permit posting date. Day 55 is November 23, 1999.

The web site address is http://www2.dep.state.fl.us/air.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 22, 1999

Mr. Michael L. Kurtz
General Manager
City of Gainesville
Gainesville Regional Utilities (GRU)
P.O. Box 147117, Station A134
Gainesville, Florida 32614-7117

Re: PROPOSED Title V Permit No.: 0010006-001-AV
Deerhaven Generating Station

Dear Mr. Kurtz:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Deerhaven Generating Station, located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit. An electronic version of this determination has been posted on the Division of Air Resources Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is *http://www2.dep.state.fl.us/air.*

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn. If you have any questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

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

CHF/tbc

Enclosures

copy furnished to:
Mr. Darrell DuBose, GRU
Mr. Thomas W. Davis, P.E., ECT
Ms. Yolanta E. Jonynas, GRU
Mr. Chris Kirts, P.E., NED
Ms. Patricia Reynolds, NEDBO
Mr. Gregg Worley, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Elizabeth Bartlett, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Gainesville Regional Utilities for the Deerhaven Generating Station, located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County, was clerked on June 17, 1999. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the Gainesville Sun on June 29, 1999. The Revised DRAFT Title V Air Operation Permit was available for public inspection at the Department of Environmental Protection's Northeast District Office in Jacksonville and the permitting authority's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on July 1, 1999.

II. Public Comment(s).

Comments were received, but the Revised DRAFT Title V Operation Permit was not reissued. The comments were not considered significant enough to reissue the Revised DRAFT Title V Permit and require another Public Notice. Comments were received from one respondent. Listed below are responses to the *significant* comments in the letters. The comments are not restated. Editorial and cosmetic changes requested were also made, but are not noted.

A. Two letters from the Gainesville Regional Utilities, dated August 9, 1999 and August 30, 1999, respectively, offering comments and requesting wording changes to certain of the descriptive passages and Specific Conditions of the DRAFT Permit. The significant comments, requested changes, and Department responses are noted in the table below.

REQUESTED COMMENTS AND CHANGES REGARDING THE DEERHAVEN GENERATING STATION: TITLE V PERMIT **0010006-001-AV**

No.	Permit Specific Condition Reference	Department Response
1	Addition of new Specific Condition **13.** to the Facility-wide Conditions	This requested Specific Condition has been added to the PROPOSED Permit: **13.** Except as otherwise provided herein, excess emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emission 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.]

2	Specific Condition **A.33.**	This Specific Condition has been reworded to incorporate the requested change: **A.33.** Opacity and sulfur dioxide CEMs will be used for purposes of periodic monitoring.
3	Descriptive passage for the Incinerator	The descriptive passage has been changed as requested: Type I waste is rubbish, consisting of combustible waste such as paper, cartons, rags, wood scraps, sawdust, foliage, and floor sweepings from domestic, commercial, and industrial activities.
4	Specific Condition **B.3.**	This Specific Condition has been reworded to incorporate the requested change: **B.3.** <u>Methods of Operation - Fuels</u>. Only natural gas and/or on-site generated solid Type I waste shall be fired in the incinerator. [Rule 62-213.410(1), F.A.C.]

5	Specific Condition **C.6.**	The Department disagrees with removing this Specific Condition. It is retained in the PROPOSED Permit as follows: **C.6.** <u>Sulfur Dioxide- Sulfur Content.</u> The maximum allowable percent sulfur content of coal consumed shall be limited as follows: *Maximum allowable % sulfur content =* 6.3×10^{-5} *BTU per lb of coal.* However, the applicant may petition the Department to revise this condition by installing a flue gas desulfurization unit that will insure compliance with Rule 62-296.405, F.A.C [See Specific Condition **C.5.(a)(2)**]. The boiler shall not be operated unless this condition is complied with. [Power Plant Certification PA 74-04]
6	Specific Condition **C.12.**	The Department agrees with clarifying the wording of this Specific Condition. It now reads as follows in the PROPOSED Permit: **C.12.** <u>Annual Tests Required - PM, VE, SO_2 and NOx</u>. Except as provided in Specific Conditions **E.5.** through **E.7.** of this permit, emission testing for particulate matter, visible emissions, sulfur dioxide and nitrogen oxides shall be performed annually. [Rules 62-4.070(3) and 62-213.440, F.A.C.; Power Plant Certification PA 74-04]

7	Specific Conditions **D.5.** and **D.16.**	This comment requests removing the requirement of testing the sulfur content of natural gas used, and corresponding record keeping. The Department agrees with the changes, and the PROPOSED Permit reflects this revision.

8	**Appendix I-1**	The Department agrees to add the three items noted below to the **List of Insignificant Emissions Units and/or Activities:** 22. Application of fungicide, herbicide, or pesticide. 23. Petroleum lubrication systems. 24. Asbestos renovation and demolition activities.

B. Documents on file with the permitting authority:

- Two letters from the Gainesville Regional Utilities, dated August 9, 1999, and August 30, 1999, respectively.

III. Conclusion.

The permitting authority hereby issues the PROPOSED Permit, No. **0010006-001-AV**, with the changes reflected above.

STATEMENT OF BASIS

Title V PROPOSED Permit No.: 0010006-001-AV
City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station
Alachua County

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, 62-213, and 62-214, F.A.C. 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 facility consists of two steam boilers (Unit Nos. 1 and 2) and associated steam turbines; an NSPS simple cycle combustion turbine (CT No. 3); two unregulated simple cycle combustion turbines (CT Nos. 1 and 2); a Type I waste incinerator; a recirculating cooling water system, storage and handling facilities for coal, brine salt, fly ash and bottom ash; fuel oil storage tanks; water treatment facilities; a railcar maintenance facility, and ancillary support equipment. Also, included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Fossil fuel fired steam generator No. 1 is a 75 megawatt (nominal) steam generator designated as Unit 1. The emissions unit is fired on natural gas, propane, distillate fuel oils (Nos. 1 or 2) and/or residual fuel oils (Nos. 4, 5 or 6), including on-specification used oil fuel. There is no air pollution control device on this emissions unit. The combustion gases exhaust through a single stack of 300 feet. Fossil fuel fired steam generator No. 1 began commercial operation in 1972. This emissions unit is regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. As required under the Acid Rain Program, the unit has a Continuous Emission Monitoring System (CEMS) for measuring opacity, nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2).

Fossil fuel fired steam generator No. 2 is rated at 251 MW (nominal) and is capable of burning coal, natural gas, or distillate fuel oils (Nos. 1 or 2), with emissions exhausted through a 350 ft. stack. Particulate matter emissions are controlled by an electrostatic precipitator. SO_2 emissions are minimized through the use of low-sulfur coal. Fossil fuel fired steam generator No. 2 began commercial operation in 1981. This emissions unit is regulated under Acid Rain, Phase I (NO_x Early Election) and Phase II; Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971. As required under the Acid Rain Program, the emissions unit is equipped with a Continuous Emission Monitoring System for measuring opacity, SO_2, NO_x, and CO_2. The NO_x and opacity monitors are also required pursuant to the New Source Performance Standards; the SO_2 monitor is also required under the Conditions of Certification.

Combustion turbine No. 3 is rated at 74 MW (nominal), 990.6 MMBtu/hr for distillate fuel oils (Nos. 1 or 2) and 971.1 MMBtu/hr for natural gas, with emissions exhausted through a 52 ft.

stack. Emissions are controlled by dry low-NOx combustors when firing natural gas, and by water injection when firing fuel oil. The combustion turbine began commercial operation in 1995. This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. This unit underwent a BACT Determination dated April 11, 1995. BACT limits were incorporated into the PSD permit, No. PSD-FL-212, and Power Plant Conditions of Certification (PPCC), PA 74-04. These limitations are more stringent than the NSPS SO_2 and NO_x limitations and thus assure compliance with 40 CFR 60.332, 60.333 and 60.334. As required under the Acid Rain Program, the emissions unit has a continuous emission monitoring system (CEMS) for NO_x, SO_2, and CO_2. The NO_x CEMS is used in lieu of the water/fuel monitoring and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent and thus assures compliance with 40 CFR 60.334 and 60.335.

The incinerator is a Type I waste incinerator manufactured by George L. Simmonds Co. (model number B- 215). Emissions from the incinerator are controlled with an afterburner. This emissions unit is regulated under Rules 62-210.300, Permits Required, and 62-296.401(1), F.A.C. This emissions unit is *not subject* to 40 CFR 60, Subpart E, Standards of Performance for Incinerators. The incinerator's exhaust is ducted to the stack of Steam Boiler No. 1 (E.U. ID No. 003).

Based on the initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station
Facility ID No.: 0010006
Alachua County
Initial Title V Air Operation Permit
PROPOSED Permit No.: 0010006-001-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:
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4363

Initial Title V Air Operation Permit
PROPOSED Permit No.: 0010006-001-AV

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Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
City of Gainesville, GRU
P.O. Box 147117 (A134)
Gainesville, Florida 32614-7117

PROPOSED Permit No.: 010006-001-AV
Facility ID No.: 0010006
SIC No.: 49; 4911
Project: Initial Title V Air Operation

This permit is for the operation of the City of Gainesville's, Gainesville Regional Utilities (GRU), Deerhaven Generating Station. It includes the Phase I/II NOx limitations pursuant to Rule 62-214.360(6), Florida Administrative Code (F.A.C.), in the Title IV Acid Rain Part. This facility is located at 10001 NW 13th Street, Gainesville, Alachua County; UTM Coordinates: Zone 17, 367.70 km East and 3292.60 km North; Latitude: 29° 45' 30" North and Longitude: 82° 23' 13" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, 62-213, and 62-214, F.A.C. 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 4/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (version dated 7/96)
BACT Determination dated 04/11/95
Alternate Sampling Procedure: ASP Number 97-B-01, including the Order Correcting the Scrivener's Error dated July 2, 1997

Effective Date: January 1, 2000
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/sms/tbc

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two steam boilers (Unit Nos. 1 and 2); two steam turbines; three simple cycle combustion turbines (CT) designated Nos. 1, 2 and 3; a Type I waste incinerator; a recirculating cooling water system, storage and handling facilities for coal, brine salt, fly ash and bottom ash; fuel oil storage tanks; water treatment facilities; a railcar maintenance facility; and ancillary support equipment. Boiler No. 1 is fired with natural gas, propane, distillate fuel oils (Nos. 1 or 2), and/or residual fuel oils (Nos. 4, 5, or 6) including on-specification used oil fuel. Boiler No. 2 is fired with coal, natural gas, and/or distillate fuel oils (Nos. 1 or 2). Combustion turbines Nos. 1, 2 and 3 are each fired with natural gas, and/or distillate fuel oils (Nos. 1 or 2). 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, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID Nos.	Brief Description
003	960 MMBtu/hr Steam Boiler No. 1
004	215 cubic feet/day Type I Waste Incinerator
005	2,428 MMBtu/hr Steam Boiler No. 2
006	74 MW (nominal) Simple Cycle Combustion Turbine No. 3
xxx	Coal Handling and Storage Activities

Unregulated Emissions Units and/or Activities

E.U. ID No.	Brief Description
xxx	See Appendix U-1, List of Unregulated Emissions Units and/or Activities.

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, they are specifically related to this permitting action.

<u>These documents are provided to the permittee for information purposes only:</u>
Table 1-1 and Table 1-1A, Summary of Air Pollutant Standards and Terms.
Table 2-1 and Table 2-1A, Summary of Compliance Requirements.
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers (version dated 2/05/97).
Appendix H-1, Permit History/ID Number Changes.

<u>These documents are on file with the permitting authority:</u>
Initial Title V Permit Application received June 14, 1996.
Phase II Acid Rain Application/Compliance Plan dated 12/22/95
Phase I Acid Rain permit (NO_x Early Election) dated 12/13/96
Phase II NO_x Compliance Plan dated 12/19/97
Revised DRAFT Title V Permit clerked 6/17/99

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. No person 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.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:
a. a risk management plan (RMP) when, and if, such requirement becomes applicable; and,
b. certification forms and/or RMPs according to the promulgated rule schedule.
[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 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 Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

{Permitting Note: The Department has not ordered any control devices or systems under the referenced rule}.
[Rule 62-296.320(1)(a), F.A.C.]

8. **Not federally enforceable.** Reasonable Precautions. The following techniques shall be used to control unconfined particulate matter emissions on an as needed basis:

a. Chemical or water application to unpaved road and unpaved yard and landfill areas;
b. Paving and maintenance of roads, parking areas and yards;
c. Landscaping or planting of vegetation;
d. Confining abrasive blasting where possible and appropriate,

[Rule 62-296.320(4)(c)2., F.A.C.]

{Note: This condition implements the requirements of Rule 62-296.320(4)(c)1., 3., and 4. F.A.C. (Appendix TV-3, Tile V Conditions, Condition No. 58)}

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 Northeast District office:

Department of Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4363

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 & EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

13. Except as otherwise provided herein, excess emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emission 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.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
003	960 MMBtu/hr Steam Boiler - Unit 1

Fossil fuel fired steam generator No. 1 is an 75 megawatt (nominal) steam generator designated as Unit 1. The emissions unit is fired on natural gas, distillate fuel oils (Nos. 1 or 2) and/or residual fuel oils (Nos. 4, 5 or 6), including on-specification used oil fuel. There is no air pollution control device on this emissions unit. The combustion gases exhaust through a single stack of 300 feet. Fossil fuel fired steam generator No. 1 began commercial operation in 1972.

{Permitting note(s): This emissions unit is regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. As required under the Acid Rain Program, the unit has a Continuous Emission Monitoring System (CEMS) for measuring opacity, nitrogen oxides, sulfur dioxide, and carbon dioxide. These monitors are used as indicators of compliance and periodic monitoring.}

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 rates, based on the higher heating value (HHV) of the fuel, are as follows:

E.U. ID No.	Heat Input Rate	Fuel Type
003	960 MMBtu/hr	Natural Gas
	960 MMBtu/hr	Residual Fuel Oils (Nos. 4, 5, or 6), Distillate Fuel Oils (Nos. 1 or 2), propane (for ignition), on-specification used oil
	960 MMBtu/hr	Co-firing any combination of above

[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 emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular recordkeeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test. }

A.2. Emissions Unit Operating Rate Limitation After Testing. See 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 distillate fuel oils (Nos. 1 or 2), residual fuel oils (Nos. 4, 5, or 6), natural gas, propane, and/or on-specification used oil, or any combination thereof. Used oil containing a PCB concentration equal to or greater than 50 ppm shall *not* be burned. Used oil containing PCBs above the detectable level (2 ppm) cannot be used for startup or shutdown.
[Rule 62-213.410, F.A.C.;and 40 CFR 761.20(e)] .

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 purpose 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. Except as otherwise specified in this permit, this emissions unit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. See Specific Condition **A.29.**
[Rules 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. Visible emissions above 60% opacity shall be allowed for not more than four, six (6)-minute periods, during the three-hour period of excess emissions allowed by this condition. 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 - 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.8. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, minimum three (3) - hour average, as measured by applicable compliance methods. See Specific Condition **A.19**.
[Rules 62-296.405(1)(b) F.A.C.]

A.9. Sulfur Dioxide. While combusting liquid fuels, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, minimum three (3) – hour average, as measured by applicable compliance methods. See Specific Conditions **A.20.** and **A.21.**
[Rules 62-213.440 and 62-296.405(1)(c)1.j., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. The sulfur content of liquid fuels may be used as a surrogate for the sulfur dioxide limitation and shall not exceed 2.5% sulfur, by weight. See Specific Condition **A.21.**
[Rule 62-296.405(1)(e)3., F.A.C and applicant request] .

A.11. Used Oil. Burning of on-specification used oil is allowed at this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Emissions Limitations: This emissions unit is permitted to burn on-specification used oil, which contains a PCB concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

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

b. Quantity Limitation: This emissions unit is permitted to burn "on-specification" used oil, not to exceed 1.5 million gallons during any consecutive 12 month period.

c. PCB Limitation: Used oil containing a PCB concentration of 50 or more ppm shall not be burned in this emission unit. Used oil shall not be blended to meet this requirement.

d. Operational Requirements: On-specification used oil with a PCB concentration less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration above the detectable level (2 ppm) shall not be burned during periods of startup or shutdown.

e. Testing Requirements: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:
(1) Arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs.
(2) Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
(3) Alternatively, the owner or operator may rely on other analyses or other information to make the determination that the used oil meets the specifications of 40 CFR 279.11. Documentation used to make the determination shall be maintained at the facility.

f. Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records in a form suitable for inspection at the facility by the Department:
(1) The gallons of on-specification used oil placed in inventory each month.
(2) The total gallons of on-specification used oil placed in inventory in the preceding consecutive 12-month period.
(3) Copies of the analyses or other information required above.
[40 CFR 279.72, 40 CFR 279.74(b) and 761.20(e)]

g. Reporting Requirements:

The owner or operator shall submit, with the Annual Operating Report form, the analytical results or other information referenced in Specific Condition **A.11e(3)** and the total amount of on-specification used oil placed in inventory during the previous calendar year. The above record shall be maintained in a form suitable for inspection, retained for a minimum of five years.
[Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

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 delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See Specific Conditions **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. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., 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 exceedances of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee may elect to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel anlysis provided by the vendor or the permittee upon delivery.** See Specific Conditions **A.15.** and **A.21.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.]

A.21. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-90, ASTM 4177-82 or both, ASTM D4057-88 and ASTM D129-91, or the latest edition of the above ASTM methods.
[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 each 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 three 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 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.
a. The minimum period of observation for a compliance test for Unit 1 is 60 minutes.
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).

(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 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 fuel for a total of no more than 400 hours. See Specific Condition **A.29.**

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; See Specific Condition **A.28.**

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. See Specific Condition **A.29**.

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 that 400 hours. See Specific Condition **A.29**.

9. The owner or operator shall notify the Department's Northeast 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 Northeast 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's Northeast District office.

(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 this emissions unit while burning:

a. only gaseous fuel(s)
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other than during startup, for no more than 400 hours per year; or
c. only liquid fuel(s), other than during startup, for no more 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 this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other than during startup, for no more than 400 hours per year; or
c. only liquid fuel(s), other than during startup, for no more than 400 hours per year.

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

Record keeping and Reporting Requirements

A.30. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Northeast District office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

A.31. Submit to the Northeast District office 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.32. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Northeast District office on the results of each such test.
(b) The required test report shall be filed with the Northeast District office 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.]

Periodic Monitoring

A.33. Opacity and sulfur dioxide CEMs will be used for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C.]

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	Incinerator

This emissions unit is a Type I waste incinerator manufactured by George L. Simmonds Co. (model number B-215). Emissions from the incinerator are controlled with an afterburner. Type I waste is rubbish, consisting of combustible waste such as paper, cartons, rags, wood scraps, sawdust, foliage, and floor sweepings from domestic, commercial, and industrial activities.

{Permitting notes: This emissions unit is regulated under Rules 62-210.300, Permits Required, and 62-296.401(1), F.A.C. This emissions unit is *not subject* to 40 CFR 60, Subpart E, Standards of Performance for Incinerators. The incinerator's exhaust is ducted to the stack of Steam Boiler No. 1 (E.U. ID No. 003).}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum input rate (operation rate) is as follows:

E.U. ID No.	Cubic feet per day	Fuel Type
004	215	Type I Waste – rubbish

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

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

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **B.11.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels. Only natural gas and/or on-site generated solid Type I waste shall be fired in the incinerator.
[Rule 62-213.410(1), F.A.C.]

B.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. The hours of operation shall be recorded.
[Rules 62-4.160(2) and 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 purpose only. This table does not supersede any of the terms or conditions of this permit.}

B.5. Visible Emissions. No visible emissions (5 percent opacity) are allowed from this emission unit except that visible emissions not exceeding 20 percent opacity are allowed for up to three (3) minutes in any one hour period.
[Rule 62-296.401, F.A.C.]

Excess Emissions

B.6. Excess emissions from this emissions unit 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.7. 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.8. 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.}

B.9. This incinerator is regulated individually and must be tested individually. Due to the common stack, one unit must be shut down while the other unit is being tested.
[Rules 62-4.070(3) and 62-213.440(1), F.A.C.]

B.10. The test method for visible emissions shall be DEP Method 9, referenced in Chapter 62-297, F.A.C.
[Rules 62-296.401.(1)(c) and 62-297.401, F.A.C.]

B.11. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); 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.12. 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.13. 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

c. 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.

9. The owner or operator shall notify the Department's Northeast 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, 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]

Recordkeeping and Reporting Requirements

B.14. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Northeast District office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

B.15. 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 Northeast District office on the results of each such test.
(b) The required test report shall be filed with the Department's Northeast District office 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.]

Subsection C. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
005	2,428 MMBtu/hr Steam Boiler - Unit 2

Fossil fuel fired steam generator No. 2 is rated at 251 MW (nominal) and is capable of burning coal, natural gas, and/or distillate fuel oils (Nos. 1 or 2), with emissions exhausted through a 350 ft. stack. This generator is a dry bottom wall-fired boiler. Particulate matter emissions are controlled by an electrostatic precipitator. Sulfur dioxide emissions are minimized through the use of low-sulfur coal. Fossil fuel fired steam generator No. 2 began commercial operation in 1981.

{Permitting note(s): This emissions unit is regulated under Acid Rain, Phase I (NO_x Early Election) and Phase II; Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971. As required under the Acid Rain Program, the unit is equipped with a Continuous Emission Monitoring System for measuring opacity, sulfur dioxide (SO_2), nitrogen oxides (NO_x) and carbon dioxide (CO_2). The NO_x and opacity monitors are also required pursuant to the New Source Performance Standards; the SO_2 monitor is also required under the Conditions of Certification. These monitors are used as indicators of compliance.}

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

{Permitting note: In addition to the requirements listed below, this emissions unit is also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

<u>Essential Potential to Emit (PTE) Parameters</u>

C.1. <u>Permitted Capacity</u>. The maximum operation heat input rates, based on the higher heating value (HHV) of the fuels, are as follows:

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
005	591	Natural Gas
	900	Distillate Fuel Oils (Nos. 1 or 2)
	2,428	Coal
	2,428	Co-firing any combination of the above

[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. Regular recordkeeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test. }

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.10.**
[Rule 62-297.310(2), F.A.C.].

C.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are coal, natural gas, and/or distillate fuel oils (Nos. 1 or 2). Fuels may be co-fired in any combination.
[Rule 62-213.410, F.A.C.; PA 74-04] .

Emission Limitations and Standards

C.4. Pursuant to 40 CFR 60.42 Standard For Particulate Matter.
(a) No owner or operator 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), minimum three (3)-hour average, derived from fossil fuel.
(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)]

C.5. Pursuant to 40 CFR 60.43 Standard For Sulfur Dioxide.
(a) No owner or operator 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), minimum three (3)-hour average, derived from liquid fossil fuel..
(2) 520 nanograms per joule heat input (1.2 lb per million Btu), minimum three (3)-hour average, derived from solid fossil fuel.
(b) When different fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

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

In lb/MMBtu the formula is:

$$PS_{SO2} = [y(0.80)+z(1.2)]/y+z$$

Where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule or lb/MMBtu, heat input derived from all fossil fuels 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.

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

C.6. Sulfur Dioxide- Sulfur Content. The maximum allowable percent sulfur content of coal consumed shall be limited as follows: *Maximum allowable % sulfur content* = $6.3 X 10^{-5}$ *BTU per lb of coal.* However, the applicant may petition the Department to revise this condition by installing a flue gas desulfurization unit that will insure compliance with Rule 62-296.405, F.A.C [See Specific Condition **C.5.(a)(2)**]. The boiler shall not be operated unless this condition is complied with.
[Power Plant Certification PA 74-04]

C.7. Flue Gas Desulfurization Equipment Requirement Prior to installation of any FGD (flue gas desulfurization) equipment, plans and specifications for such equipment shall be submitted to the Department for review and approval.
[Power Plant Certification PA 74-04]

C.8. Pursuant to 40 CFR 60.44 Standard For Nitrogen Oxides.
(a) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu), minimum three (3)-hour average, derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu), minimum three (3)-hour average, derived from liquid fossil fuel.
(3) 300 nanograms per joule heat input (0.70 lb per million Btu), minimum three (3)-hour average, derived from solid fossil fuel.
(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = (86x + 130y + 300z)/(x+y+z)$$

In lb/MMBtu the formula is:

$$PS_{NOx} = (0.20x + 0.30y + 0.70z)/(x+y+z)$$

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

[40 CFR 60.44(a) & (b)]

Test Methods and Procedures

C.9. Pursuant to 40 CFR 60.46 Test methods and Procedures.
(a) 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 [this Specific Condition], except as provided in 40 CFR 60.8(b) [Specific Condition **F.2.**]. Acceptable alternative methods and procedures are given in 40 CFR 60.46(d) [Specific Condition **C.9.(d)**].
(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_X standards in 40 CFR 60.42, 60.43, and 60.44 [Specific Conditions **C.4, 5** and **8**] as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each test run using the following equation [or the procedure specified in Specific Condition **C.9.(d)(1)**]:

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

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

C = concentration of pollutant, ng/dscm (lb/dscf).
% O_2 = 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. [Alternatively Method 17 may be used pursuant to Condition **C.9.(d)(2)**.]

(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 O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in 40 CFR 60.11 [Condition **F.3.**] shall be used to determine opacity except as otherwise allowed under Condition G.3.(e)(5).

(4) Method 6 [or the methods specified in Condition **C.9.(d)(3)**] shall be used to determine the SO_2 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 O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 [or the methods specified in Condition **C.9.(d)(5)**] shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 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 [or Method 3A per Condition **C.9.(d)(7)**] shall be used to determine the O_2 concentration (%O_2). 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 O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels 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) [Conditions **C.5** and **C.8**.] 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) or the latest edition,(s) (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.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section [Condition **C.9.**] or in other section [conditions] as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

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

$$E = C\ F_c\ (100 / \%CO_2)$$

where:

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

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

$\%CO_2$ = 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 [or Method 3A pursuant to Condition **C.9.(d)(7)**] 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) [Condition **C.9.(b)**]. Then if F_o (average of three runs), as calculated from the equation in Method 3B [or_Method 3A pursuant to Condition D.9.(d)(7))], 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 Fo 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) [Condition **C.9.**].

(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(a), (b), (c) & (d)]

C.10. Operating Rate During Testing. Testing of emissions shall be conducted with each 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.]

Monitoring of Operations

C.11. Record Fuel Input. The owner or operator shall maintain a daily log of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values to facilitate calculations of emissions. Stack monitoring, fuel usage and fuel analyses data shall be reported to the Department on a quarterly basis in accordance with 40 CFR 60.7. See Specific Condition **F.1.** Such monitoring shall include amounts of distillate (Nos. 1 or 2) fuel oil and natural gas used for start up or flame stabilization.
[Power Plant Certification PA 74-04]

C.12. Annual Tests Required - PM, VE, SO_2 and NOx. Except as provided in Specific Conditions **E.5.** through **E.7.** of this permit, emission testing for particulate matter, visible emissions, sulfur dioxide and nitrogen oxides shall be performed annually.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; Power Plant Certification PA 74-04]

C.13. Pursuant to 40 CFR 60.45 Emission and Fuel Monitoring.
(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in 40 CFR 60.45(b) [Specific Condition **C.13.** (b)]. A continuous emission monitoring system ("CEMS") installed and operated in accordance with 40 CFR 75 may be used to meet the monitoring requirements of 40 CFR 60 (specified herein).
(b) Not applicable.
(c) For performance evaluations under 40 CFR 60.13(c) [Specific Condition **F.5.(c)**] and calibration checks under 40 CFR-60.13 (d) [Specific Condition **F.5.(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) [Specific Condition **C.9.**].
(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 [incorporated by reference].

(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 except as otherwise specified in 40 CFR 75:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	{1}	500
Liquid	1,000	500
Solid	1,500	1000
Combinations	1,000y + 1,500z	500(x+y)+1,000z

{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) [Specific Condition **C.13.**] for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm except as otherwise specified in 40 CFR 75.
(d) [Reserved]
(e) For any continuous monitoring system installed under 40 CFR 60.45 (a), [Specific Condition **C.13.**] 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 except as otherwise provided under 40 CFR 75:

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

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f). [Specific Condition **C.13.(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 except as otherwise provided under 40 CFR 75:

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

where:

E, C, F_c and % CO_2 are determined under 40 CFR 60.45(f) [Specific Condition **C.13.(f)**].

(f) The values used in the equations under 40 CFR 60.45 (e)(1) and (2) [Specific_Condition **C.13.**] 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) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45 (a). [Specific Condition **C.13.**].

(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, except as otherwise provided in 40 CFR 75:

(i) Not applicable.

(ii) For *subbituminous and bituminous coal* as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/million Btu) and F_c = 0.486×10^{-7} scm CO_2 /J (1,810 scf CO_2 /million Btu).

(iii) For *liquid fossil fuels* (Nos. 1 and 2), F = 2.476×10^{-7} dscm/J (9,220 dscf/million Btu) and F_c = 0.384×10^{-7} scm CO_2 /J (1,430 scf CO_2 /million Btu).

(iv) For *gaseous fossil fuels*, F = 2.347×10^{-7} dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, F_c = 0.279×10^{-7} scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /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 CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45 (f)(4) [Specific Condition **C.13.**].

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

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

(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)

$$F_C = \frac{321x10^3\ (\%C)}{GCV}$$
(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.)

(6) For affected facilities firing *combinations of fossil fuels* , the F or F_C factors determined by paragraphs 40 CFR 60.45 (f)(4) or (f)(5) [Specific Conditions **C.13.(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.

Excess Emission Reports.
(g) Excess emission and monitoring system performance ("MSP") 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) [Specific Condition **F.1.**]. 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 [Specific Condition **C.5.**].

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44 [Specific Condition **C.8.**].

[40 CFR 60.45(g)]

Pursuant to 40 CFR 60.13 (h) [Specific Condition **F.5.(h)**], 1-hour averages of SO2 and NOx shall be computed from four (4) or more data points equally spaced over each 1-hour period.

Other NSPS Subpart D Conditions

C.14. Pursuant to 40 CFR 60.41 Definitions. As used in this Subsection of the permit, the definitions in 40 CFR 60.41 apply, as well as additional definitions under Subpart A of 40 CFR 60.

Common Conditions

C.15. This emissions unit is also subject to Specific Conditions **E.1.** through **E.14.** contained in **Subsection E. NSPS Common Conditions.**

C.16. This emissions unit is also subject to Specific Conditions **F.1.** through **F.6.** contained in **Subsection F. NSPS General Conditions.**

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
006	Combustion Turbine No. 3

Simple Cycle Combustion Turbine No. 3, DHCT3, is rated at 74 MW (nominal), 990.6 MMBtu/hr for distillate fuel oils (Nos. 1 or 2) and 971.1 MMBtu/hr for natural gas, with emissions exhausted through a 52 ft. stack. Emissions are controlled by dry low-NOx combustors when firing natural gas, and by water injection when firing fuel oil. The combustion turbine began commercial operation in 1996.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. This unit underwent a BACT Determination dated April 11, 1995. BACT limits were incorporated into the PSD permit, No. PSD-FL-212, and Power Plant Conditions of Certification (PPCC), PA 74-04. These limitations are more stringent than the NSPS sulfur dioxide and nitrogen oxides limitations and thus assure compliance with 40 CFR 60.332, 60.333 and 60.334. As required under the Acid Rain Program, the unit has a continuous emission monitoring system ("CEMS") for SO_2, NO_x, and carbon dioxide. The NO_x CEMS is used in lieu of the water/fuel monitoring and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent and thus assures compliance with 40 CFR 60.334 and 60.335.}

The following Specific Conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rates, based on the higher heating values of the fuel, are as follows:

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
006	971.1*	Natural Gas
	990.6*	Distillate Fuel Oils (Nos. 1 or 2)

* Based on 100% load, 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions).
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; PA 74-04 and PSD-FL-212]

{Permitting note: Heat input will vary depending on ambient conditions and the DHCT3 characteristics.}

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 95-100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular recordkeeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test. }

D.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **D.9.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation - Fuels. Only natural gas and/or distillate fuel oils (Nos. 1 or 2) shall be fired in the combustion turbine. Fuels may be co-fired.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

D.4. Visible Emissions. Visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.
[PA 74-04 and PSD-FL-212]

D.5. Sulfur Dioxide - Sulfur Content. The distillate fuel oil sulfur content shall not exceed 0.05 percent, by weight. See Specific Condition **D.11.**
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; and, Applicant's Request]

D.6. Allowable Emissions. The maximum allowable emissions from the DHCT3, when firing natural gas or distillate fuel oils (Nos. 1 or 2), in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, load changing, fuel switching and malfunction pursuant to Rule 62-204.800(7), F.A.C., and the BACT analysis.

Pollutant	Fuel	BACT Standard	Lbs/Hr	TPY
NO_x*	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined (c)	239
PM_{10}	Gas	Good combustion	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur fuel oil, max. 0.05% sulfur by weight	15(d)	15(b)(d)
		Good combustion; low sulfur fuel oil, max. 0.05% sulfur by weight	Combined (c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight	53(d) Combined(c)	53(b)(d) 81
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight	6(d) Combined(c)	6(b)(d) 9

*These values will be calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through combustion of pipeline natural gas and fuel oil sulfur analysis.
[PA 74-04 and PSD-FL-212]

Test Methods and Procedures

D.7. Annual Compliance Tests. Except as otherwise provided in Specific Condition **E.7.** of this permit, emission testing for visible emissions and nitrogen oxides shall be performed annually in accordance with Specific Condition **D.9.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NOx.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212]

D.8. Testing for SO_2, PM_{10}, H_2SO_4. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 (sulfuric acid or SAM) mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using the ASTMs listed in Specific Condition **D.11.** for the sulfur content of liquid fuels.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212]

D.9. Operating Rate During Testing and Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input (based on the high heating value of the fuel) vs. ambient temperature). If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value (corrected for ambient air 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. 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. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests.
[PA 74-04 and PSD-FL-212]

D.10. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the *liquid fuel* sulfur limit by fuel sampling and analysis. See Specific Conditions **D.5**, **D.8,** **D.11**, and **D.18**. The permittee shall demonstrate compliance with the *gaseous fuel* sulfur limit via record keeping. See Specific Condition **D.16.**
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

D.11. Fuel Sampling & Analysis. The following fuel oil sampling and analysis program in accordance with the fuel sampling and analysis requirements of 40 CFR 75, Appendix D shall be used to demonstrate compliance with Specific Conditions **D.5.**, **D.6.**, and **D.8.**:

a. Determine and record the fuel sulfur content, percent by weight, for *liquid fuels* using ASTM D4057-88 and ASTM D 2880-71, ASTM D2622-92, ASTM D4294-90, or ASTM D129-9, or the latest edition(s).

[Rule 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212]

Monitoring of Operations

D.12. Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides and sulfur dioxide in accordance with the requirements of 40 CFR 75.
[PA 74-04, and PSD-FL-212]

D.13. Excess Emissions by CEMS. The CEMS for NOx shall be used to determine periods of excess emissions. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. One-hour periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions in accordance with Specific Condition **F.5.(h)** and following the format of 40 CFR 60.7 (c) [Specific Condition **F.1.(c)**]. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. FBN levels and water/fuel monitoring are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40CFR 60.335 (c) (2) will be replaced by certification tests on the NOx CEMS.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212]

D.14. The continuous emission monitor must comply with Rule 62-297.520, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 ; or, if applicable, 40 CFR 75, Appendix A and Appendix B. Upon request from the Department, the CEMs NOx emission rates shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; and, applicant request]

D.15. The permittee shall utilize dry low-NO_X combustors on the DHCT3 for NO_X control when firing natural gas. Control of NO_X when firing distillate fuel oils (Nos. 1 or 2) shall be accomplished by water injection.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; and, BACT]

Record Keeping and Reporting Requirements

D.16. Additional Reports Required. The owner or operator shall report the following with the Air Operating Report (AOR): sulfur and nitrogen content, by weight, and higher heating value(s) of the fuel oil being fired, annual consumption of distillate fuel oil and natural gas, hours of operation per fuel usage.
[Rule 62-210.370(3), F.A.C.; PA 74-04 and PSD-FL-212]

D.17. Custom Fuel Monitoring Schedule. The sulfur and nitrogen content of the fuel oil being fired in the combustion turbine shall be determined in accordance with this schedule. Monitoring of the nitrogen and sulfur content in natural gas is *not* required.

a. Fuel oil: On each occasion that fuel oil is transferred to the storage tank from another source.
b. Natural gas: Not required.
The records of natural gas and distillate fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.
[PA 74-04 and PSD-FL-212; and, Applicant's Request]

[Permitting note: Monitoring of the pipeline natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal and the SO2 emissions are measured using monitoring systems that have been certified by EPA in accordance with 40 CFR 75.]

Other Conditions

D.18. These emissions units are also subject to Specific Conditions **E.1** through **E.14** contained in **Subsection E. NSPS Common Conditions.**

D.19. These emissions units are also subject to Specific Condition **F.1** through **F.6** contained in **Subsection F. NSPS General Conditions.**

Subsection E. NSPS Common Conditions.

E.U. ID No.	Brief Description
005	2,428 MMBtu/hr Steam Boiler - Unit 2
006	Combustion Turbine No. 3
xxx	Coal Handling and Storage Activities

The following Conditions apply to the emissions unit(s)/activities listed above except as noted below: Specific Conditions **E.1.**, **E.4.**, **E.5.**, **E.6.**, **E.7.**, **E.9.**, **E.10.**, **E.12.**, and **E.14.** *do not apply* to E.U. ID No. xxx, Coal Handling and Storage Activities.

Essential Potential to Emit (PTE) Parameters

E.1. Hours of Operation. The emission unit 005 (Unit 2) may operate continuously, i.e., 8,760 hours/year. The emission unit 006 (DHCT3) is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing distillate fuel oils (Nos. 1 or 2).
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

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.2. Excess emissions 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.]

E.3. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

E.4. 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 and Table 2-1A, Summary of Compliance Requirements, summarize information for convenience purposes only, These tables does not supersede any of the terms or conditions of this permit.}

E.5. 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. Except as otherwise specified in an applicable subsection, 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; See Specific Condition **E.7.**
   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
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 (applicable to Unit 2 only). See Specific Condition **E.6**.
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 (applicable to CT3 only).
9. The owner or operator shall notify the Department's Northeast 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, 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.6. When PM Tests Not Required (applicable to Unit 2 only). Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s), other than during startup, for no more than 400 hours per year; or
c. only liquid fuel(s), other than during startup, for no more than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

E.7. Visible Emissions. When VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for the emissions units ID. No. 005 and 006 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 62-4.070(3), F.A.C.]

E.8. Visible Emissions. The test method for visible emissions for emissions units 005 (Unit2), 006 (CT3) and xxx (Coal Handling and Storage Activities), 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.) or as otherwise provided in Specific Condition **F.3.(b)**.
[Rules 62-204.800 and 62-297.401, F.A.C.; Subpart Y, 40 CFR 60.254 (b) and 40 CFR 60.11]

E.9. 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.
[Rule 62-297.310(1), F.A.C. and 40 CFR 60.8]

E.10. 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.11. 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. The minimum period of observation for a compliance test for these units is:
   a. Unit 2: sixty (60) minutes.
   b. CT3: thirty (30) minutes.
   c. Coal Handling and Storage Facilities: thirty (30) minutes.

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.

(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.12. 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 (version dated 10/07/96), attached to this permit.

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

Record Keeping and Reporting Requirements

E.13. Malfunctions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Northeast District office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Northeast District office.

[Rule 62-210.700(6), F.A.C.]

E.14. 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 Northeast District office on the results of each such test.

(b) The required test report shall be filed with the Department's Northeast 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 Northeast 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 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.]

Subsection F. 40 CFR 60, NSPS General Conditions.

E.U. ID No.	Brief Description
005	2,428 MMBtu/hr Steam Boiler - Unit 2
006	Combustion Turbine No. 3
xxx	Coal Handling and Storage Activities

{Note: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions.

The following Specific Conditions apply to the NSPS emissions units listed above, except that Specific Conditions **F.1.(a)(4)(c** through **e)**, **F.5.** and **F.6.** *do not apply* to E.U. ID. xxx, Coal Handling and Storage Activities (see Subsection H):

F.1. Pursuant to 40 CFR 60.7 Notification And Record Keeping.
(a) Any owner or operator subject to the provisions of this part 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.
(b) The owner or operator subject to the provisions of this part 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.
(c) 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) and Condition **F.1.(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) [Condition **F.5.(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.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 (version dated 7/96) 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) [Condition **F.1.(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) [Condition **F.1. (c)**] shall both be submitted.

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance, version dated 7/96]

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, 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 an applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (3) (2) of this section.

(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 ground 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 fully 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 paragraphs (e) (1) and (e) (2) of this section.

(f) The owner or operator subject to the provisions of this part 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 this part recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

F.2. Pursuant to 40 CFR 60.8 Performance Tests.
(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.
(c) 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.
(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

F.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.
(a) Compliance with standards in this part, other than opacity standards, shall be determined only by and in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with EPA Reference Method 9, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11 (e)(5) [Condition **F.3.(e)(5)**]
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) 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.
(e)(5) 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 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) [Condition **F.5.(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]

F.4. Pursuant to 40 CFR 60.12 Circumvention.
No owner or operator subject to the provisions of this part 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.5. Pursuant to 40 CFR 60.13 Monitoring Requirements.
(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section 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 to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
(b) Not applicable.
(c) 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) [Condition **F.3.(e)(5)**], he/she 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 40 CFR 60.8 and as described in 40 CFR 60.11 .(e)(5) [Condition **F.3.(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) [Condition **F.5.(c)**] at least 10 days before the performance test required under 40 CFR 60.8 is conducted.
(2) Except as provided in 40 CFR 60.13 (c)(1) [Condition **F.5.(c)(1)**], the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.
(d)(1) Owners and operators of all continuous emission monitoring systems 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.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13 (d) [Condition **F.5.(d)**], all continuous monitoring systems 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) [Condition **F.5.(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) [Condition **F.5.(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.

(f) 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. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) Not applicable.

(h) 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]

F.6. Pursuant to 40 CFR 60.17 Incorporations by Reference.

The materials listed in 40 CFR 60.17 are incorporated by reference in the corresponding sections noted.
[Note: See 40 CFR 60.17 for materials incorporated by reference.]

Section III. Emissions Unit(s) and Conditions.

Subsection G. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
xxx	Coal Handling and Storage Activities

{Permitting notes: This emissions unit/activity is regulated under Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, with the exception of Emission Points CH-006, 007, and 008.}

SUMMARY OF COAL HANDLING ACTIVITIES:

Source Description	Emission Point ID	Emission Type
Coal Handling - Railcar Unloading; Bottom Discharge	CH-001	Fugitive (F)
Coal Handling - Belt Conveyor 2 to Belt Conveyor 3A	CH-002	F
Coal Handling - Belt Conveyor 2 to Belt Conveyor 3B	CH-003	F
Coal Handling - Belt Conveyor 3A to Storage Pile	CH-004	F
Coal Handling - Belt Conveyor 3B to Storage Pile	CH-005	F
Coal Storage - Ready Storage Pile	CH-006	F
Coal Storage - Episodic Storage Pile	CH-007	F
Coal Storage - Main Storage Pile	CH-008	F
Coal Handling - Dozer Operations on Storage Pile	CH-009	F
Coal Handling - Crusher Building	CH-010	F
Coal Handling - Coal Bunker Building	CH-011	F
Coal Handling - Belt Conveyor 4A to Surge Bin		
Coal Handling - Crusher Building: Crusher Feeder to Crusher		
Coal Handling - Crusher Building: Crusher to Belt Conveyor		
Coal Handling - Belt Conveyor 5A to Belt Conveyor 6A		
Coal Handling - Coal Bunker Building; Belt Conveyor 6A		
to Bunkers		

Note: Emissions are controlled by the enclosure of conveying, crushing, and bunkering equipment.

{Permitting note: By letters dated June 28, 1995 and December 2, 1996, GRU submitted to the Department information that demonstrated that the 20% opacity limit on the coal handling and storage sources could be met (without compromising the emissions estimated and modeled in the Site Certification application) through enclosure of the conveying, crushing and bunkering equipment alone. Visual emission observations by the Department confirmed GRU's findings regarding compliance with the opacity limits.}

Essential Potential to Emit (PTE) Parameters

G.1. Permitted Capacity. The maximum coal throughput rate shall not exceed 660,000 tons per year. [Rules 62-4.160(2) F.A.C., 62-210.200 (PTE) F.A.C.]

G.2. Particulate matter emissions from the coal handling facilities. The permitee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 20 percent opacity.
[40 CFR 60. 252 (c) and Power Plant Certification PA 74-04]

Test Methods and Procedures

G.3. Visible Emissions – See Specific Condition **E.8**.

Other Conditions

G.4. These emissions units are also subject to Specific Conditions contained in **Subsection E. NSPS Common Conditions except as otherwise noted therein.**

G.5. These emissions units are also subject to Specific Conditions contained in **Subsection F. NSPS General Conditions, except as otherwise noted therein.**

Section IV. This section is the Acid Rain Part.

Operated by: City of Gainesville
ORIS Code: 0663

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

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

E.U. ID No.	Brief Description
003	960 MMBtu/hr Steam Boiler - Unit 1
005	2,428 MMBtu/hr Steam Boiler - Unit 2
006	Combustion Turbine No. 3

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. Phase II Permit Application (DEP Form No. 62-210.900(1)(a)), dated 12/22/95.
b. Letter dated January 9, 1996 amending the original application.
c. Letter dated January 26, 1996 correcting DEP's unit designation for CT3 on the State of Florida Acid Rain Facilities table contained in the application completeness determination.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003	2004
003	B1	SO_2 Allowances, under Table 2 of 40 CFR Part 73	98*	98*	98*	98*	98*
005	B2	SO_2 Allowances, under Table 2 of 40 CFR Part 73	8268*	8268*	8268*	8268*	8268*
006	CT3	SO_2 Allowances, under Table 2 of 40 CFR Part 73	0*	0*	0*	0*	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S. EPA under Table 2 of 40 CFR 73.

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

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., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

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

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

{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/II, for City of Gainesville, GRU, Deerhaven Generating Station.

Facility ID No.: 0010006
ORIS code: 0663

E.U. ID No.	Brief Description
005	2,428 MMBtu/hr Steam Boiler - Unit 2

1. The owners and operators of this Phase I/II Acid Rain unit must comply with the standard requirements and special provisions set forth in the permit listed below:
a. Phase I permit dated 12/13/96.
[Chapter 62-213, F.A.C.]

2. Nitrogen oxide (NO_x) requirements for this Acid Rain unit are as follows:

E.U. ID No.	EPA ID	NO_x limit*
005	B2	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_x early election compliance plan for **unit B2**. 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. 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.

* Based on the Phase II NO_x Compliance Plan dated December 19, 1997.

3. Comments, notes, and justifications: none.

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

City of Gainesville, GRU
Deerhaven Generating Station

PROPOSED Permit No.: 0010006-001-AV

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.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
xxx	Lime Silo
xxx	Soda Ash Silo
xxx	Brine Spray Dryer
xxx	Loading of Dried Brine to Trucks
xxx	Brine Trucks to Onsite Landfill, Full
xxx	Brine Trucks to Onsite Landfill, Empty
xxx	Unloading of Brine from Trucks to Onsite Landfill
xxx	Brine Landfill
xxx	Dozer Operations on Brine Landfill
xxx	Pneumatic Transfer of Fly Ash from DH-2 to Fly Ash Silo
xxx	Dry Transfer from Fly Ash Silo to Trucks (Vented to Baghouse)
xxx	Dry Transfer from Fly Ash Silo to Trucks (Fugitives)
xxx	Wet (Pug Mill) Transfer from Fly Ash Silo to Trucks (Fugitives)
xxx	Fly Ash Trucks to Onsite Landfill, Full
xxx	Fly Ash Trucks to Onsite Landfill, Empty
xxx	Fly Ash Trucks to Offsite Disposal, Full
xxx	Fly Ash Trucks to Offsite Disposal, Empty
xxx	Transfer of Wet Fly Ash from Trucks to Onsite Landfill
xxx	Dozer Operations on Fly Ash Landfill
xxx	Fly Ash Landfill
xxx	Groundwater Aerator
001	20 MW (nominal) Simple Cycle Combustion Turbine No. 1 (Draws fuel oil from the same tank as Combustion Turbine No. 3)
002	20 MW (nominal) Simple Cycle Combustion Turbine No. 2 (Draws fuel oil from the same tank as Combustion Turbine No. 3)

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

City of Gainesville, GRU **PROPOSED Permit No.:** 0010006-001-AV
Deerhaven Generating Station

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. Parts cleaning and degreasing stations
2. Storage tanks < 550 gallons
3. Distillate fuels (Nos. 1 or 2) and residual fuel oils (No. 4, 5 or 6) storage tanks > 550 gallons
4. Laboratory equipment used exclusively for chemical or physical analyses (including fume hoods and vents)
5. Fire and safety equipment
6. Turbine vapor extractor
7. Sand blasting and abrasive grit blasting
8. Equipment used for steam cleaning
9. Belt conveyors
10. Vehicle refueling operations
11. Vacuum pumps in laboratory operations
12. Equipment used exclusively for space heating, other than boilers
13. Evaporation of on-site generated boiler non-hazardous cleaning chemicals in Boiler Nos. 1 and 2 . This activity occurs once every three to five years or longer.
14. Brazing, soldering and welding.
15. One or more emergency generators which are not subject to the Acid Rain Program and have a total fuel consumption, in the aggregate, of 32,000 gallons per year or less of diesel fuel, 4,000 gallons per year or less of gasoline, and 4.4. million cubic feet per year or less of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
16. One or more heating units and general purpose internal combustion engines which are

Appendix I-1 (Continued).

not subject to the Acid Rain Program and have a total fuel consumption, in the aggregate, of 32,000 gallons per year or less of diesel fuel, 4,000 gallons per year or less of gasoline, and 4.4 million cubic feet per year or less of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.

17. Freshwater cooling towers.
18. Surface coating operations utilizing 6.0 gallons per day or less, average monthly, of coatings containing greater than 5.0 percent VOCs, by volume.
19. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
20. Degreasing units using heavier-than-air vapors exclusively, not subject to 40 CFR 63, Subpart T.
21. Railcar maintenance.
22. Application of fungicide, herbicide, or pesticide.
23. Petroleum lubrication systems.
24. Asbestos renovation and demolition activities.

{Note: Emissions units or activities which are added to a Title V source after issuance of this permit shall be incorporated into the permit at its next renewal, provided such emissions units or activities have been exempted from the requirement to obtain an air construction permit, and also qualify for exemption from permitting pursuant to Rule 62-213, F.A.C. [Rule 62-213.430(6)(a)]}

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_x combustors and will also use water injection for NO_x control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00022	0.00022	0.0004
Hg			0.0009	0.0009	0.1
Pb			0.05746	0.05746	0.6
As			0.004854	0.004854	Any

* With power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_x, SO_2, PM_{10}, and H_2SO_4 mist.

<u>Date of Receipt of a BACT Application</u>

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing), maximum based on fuel bound nitrogen 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

BACT Determination Procedure

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically infeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of up to 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas as would result from water or steam injection in the gas turbine combustor can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only <u>potentially</u> technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using a low-NO_X combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_X emissions by approximately 80%, about 58.22 tons of NO_X would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_X is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions when firing No. 2 fuel oil will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 81 tons SO_2 per year and 9 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO$_X$ Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO$_X$ for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO$_X$ control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO$_X$ combustor technology to achieve a NO$_X$ emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO$_X$ concentrations shall not be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO$_X$ emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements which is a maximum limit of 0.05% sulfur content by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR	TPY
NO_x*	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	[illegible]	[illegible]
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content by weight	[illegible]	[illegible]
			Combined(c)	[illegible]
	Oil	Good combustion limited quantity: max. 0.25% sulfur content, by weight		

*These values will be calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN monitoring is not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_x and oxygen CEMS.

Details of the Analysis May be Obtained by Contacting:

Al Linero, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

march 29, 1995
Date

Approved by:

Virginia B. Wetherell
Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

April 11th, 1995
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

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 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

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

FILING 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 Williams 3-18-97

Clerk Date

RIDA ELECTRIC POWER COORDINATING GROUP, INC. (FCG)
RED STREET, SUITE 100 • (813) 289-5644 • FAX (813) 289-5646
PA, FLORIDA 33609-1004

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

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

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.

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
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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
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

32501

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 3

1.4 Natural Gas Combustion

1.4.1 General[1-2]

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 Controls[3-5]

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/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m^3 (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 (SO_2), 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/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 8270 kcal/m^3 (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/10^6 Nm^3 (2000 gr/10^6 scf).

Table 1.4-2 (cont.).

[d] References 10,15-19. Expressed as NO_2. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). 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 (CO_2) 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/10^6 cubic meters and lb of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (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.

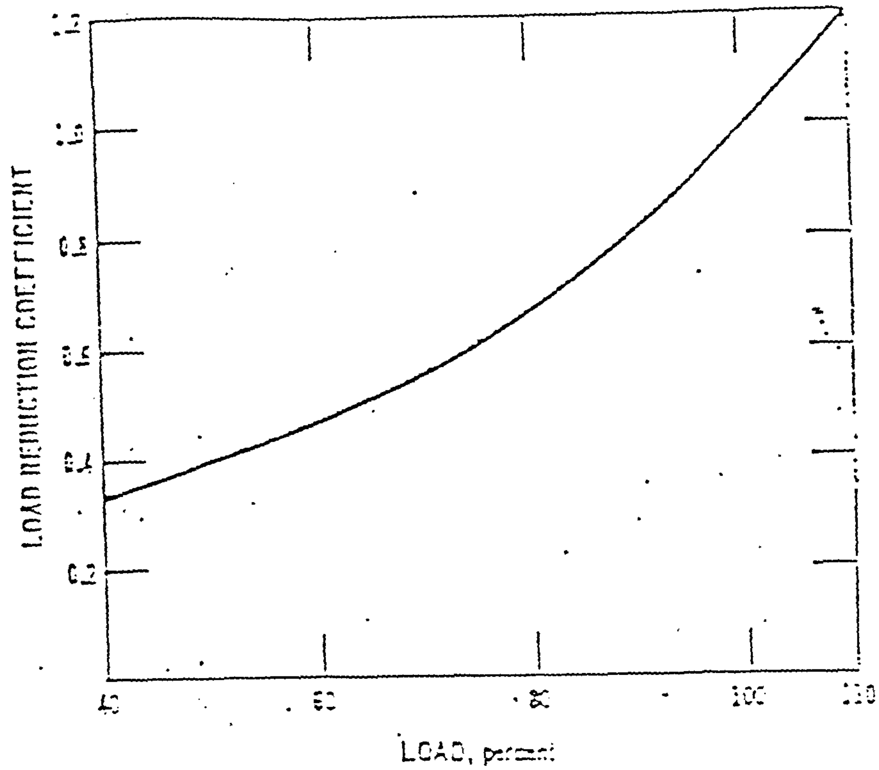

Figure 1.4-1. Load reduction coefficient as a function of boiler load.
(Used to determine NO_x reductions at reduced loads in large boilers.)

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4. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.

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15. *Emissions Test on 200 HP Boiler at Kaiser Hospital in Woodland Hills*, Energy Systems Associates, Tustin, CA, June 1986.

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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.

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Private communication from Kim Black (Industrial Combustion) to Ralph Harris (MRI). Independent Third Party Source Tests. February 7, 1993.

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. 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

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

<u>CERTIFICATE OF SERVICE</u>

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

FILING 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 Carswell Wise 7/10/97
Clerk Date

Appendix H-1. Permit History/ID Number Changes

Gainesville Regional Utilities
Deerhaven

Facility ID No.: 0010006

Permit History (for tracking purposes):

E.U. ID Nos.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
001	Combustion Turbine No. 1	AO01-202759	12/13/91	01/01/97		
002	Combustion Turbine No. 2	AO01-199846	10/02/91	11/01/96		
003	Boiler No. 1	AO01-224219	04/30/93	06/01/98		12/14/93
004	Incinerator	AO01-202758	12/13/91	01/01/97		
005	Boiler No. 2	PA74-04	05/16/78			modified 6/22/82, 01/27/87
006	Combustion Turbine No. 3	PSD-FL-212, PA74-04D	04/07/95 04/06/95			

ID Number Changes (for tracking purposes):

From: **Facility ID No.**: 31JAX010006

To: **Facility ID No.**: 0010006

Notes:

1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under valid permits that were in effect at the time of application until the Title V permit becomes effective}

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

City of Gainesville, GRU
Deerhaven Generating Station

PROPOSED Permit No.: 0010006-001-AV
Facility ID No.: 0010006

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

E. U. ID No.	Brief Description	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		
001	Combustion Turbine No.1 and	VE	Nos. 1& 2 FO	8760	< 20%			N/A	N/A	62-296.320(4)(b)	
002	Combustion Turbine No. 2	VE	Nat.Gas/propane	8760	< 20%			N/A	N/A	62-296.320(4)(b)	
003	Boiler No.1 (960 MMBtu/hr)	VE	Nos.1, 2, 4, 5, 6 F.O.	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
		VE	Used Oil	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
		VE	Nat.Gas/propane	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
	(Acid Rain Phase II Unit)	PM	Nos.1, 2, 4, 5, 6 F.O.	8760	0.1 lb/MMBtu	N/A	N/A	96.0	420.48	62-296.405(1)(b)	**A.8**
		PM	Used Oil	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	**A.8**
		PM	Nat.Gas/propane	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	**A.8**
		PM - SB**	Nos.1, 2, 4, 5, 6 F.O.	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		PM - SB**	Used Oil	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		PM - SB**	Nat.Gas/propane	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		VE- SB**	Nos.1, 2, 4, 5, 6 F.O.	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		VE- SB**	Used Oil	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		VE- SB**	Nat.Gas/propane	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		SO_2	Nos.1, 2, 4, 5, 6 F.O.	8760	2.75 lb /MMBtu	N/A	N/A	2,640.0	11,563.2	62-296.405(1)(c)1.j.	**A.9**
		SO_2	Used Oil	8760	2.75 lb /MMBtu	N/A	N/A	N/A	N/A	N/A	**A.9**
		SO_2	Nat.Gas/propane	8760	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
		% Sulfur	Nos. 4, 5, 6 F.O.	8760	max. sulfur content 2.5%, by wt.					Title V application	**A.10**
004	Incinerator- Type I Waste	VE	Rubbish/Nat. Gas	8760	5%;20%- 1 three min. period/hr.			N/A	N/A	62-296.401(1)(a)	**B.5**
xxx	Coal Handling and Storage	VE		8760	Not to exceed 20% opacity			N/A	N/A	40 CFR 60.252.(c)	**G.2**

* The "Equivalent Emissions" listed are for informational purposes.
** PM - SB and VE - SB refers to "soot blowing" and "load change."
F.O. = Fuel Oil

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

City of Gainesville, GRU
Deerhaven Generating Station

PROPOSED Permit No.: 0010006-001-AV
Facility ID No.: 0010006

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

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/ Year	Allowable Emissions Standard(s)	Allowable Emissions lbs./hour	Allowable Emissions TPY	Equivalent Emissions* lbs./hour	Equivalent Emissions* TPY	Regulatory Citation(s)	See Permit Condition(s)
		VE	Nat. Gas	3900	10% Opacity			N/A	N/A	BACT	**D.4**
006	Combustion Turbine No. 3	VE	Nos.1 and 2 F.O.	2000	10% Opacity			N/A	N/A	BACT	**D.4**
	74.4 MW	NOx	Nat. Gas	3900	15 ppmvd @ 15 % Oxygen			58.0	113.0	BACT	**D.6**
		NOx	Nos.1 and 2 F.O.	2000	42 ppmvd @ 15 % Oxygen			184.0	184.0	BACT	**D.6**
		NOx	Gas/Nos. 1 & 2 F.O	1900/2000					239.0	BACT	**D.6**
		SO_2	Gas	3900		29.0	57.0	29.0	57.0	BACT	**D.6**
	(Acid Rain Phase II Unit)	SO_2	Nos.1 and 2 F.O.	1900		53.0	53.0	53.0	53.0	BACT	**D.6**
		SO_2	Gas/Nos. 1 & 2 F.O	1900/2000			81.0		81.0	BACT	**D.6**
		PM_{10}	Nat. Gas	3900		7.0	14.0	7.0	14.0	BACT	**D.6**
		PM_{10}	Nos.1 and 2 F.O.	2000		15.0	15.0	15.0	15.0	BACT	**D.6**
		PM_{10}	Gas/Nos. 1 & 2 F.O	1900/2000			22.0		22.0	BACT	**D.6**
		SAM	Nat. Gas	3900		3.0	6.0	3.0	6.0	BACT	**D.6**
		SAM	Nos.1 and 2 F.O.	2000		6.0	6.0	6.0	6.0	BACT	**D.6**
		SAM	Gas/Nos. 1 & 2 F.O	1900/2000			9.0		9.0	BACT	**D.6**
		% sulfur	Nat. Gas							BACT	**D.5**
		% sulfur	Nos.1 and 2 F.O.	0.05%						BACT	**D.5**
005	Boiler No.2	VE	Coal,Gas,or Nos.1&2 F.O	8760	20%; 27% - 1 six min. period/hr.			N/A	N/A	40 CFR 60.42(a)1&2	**C.4**
	2,428 MMBtu/hr	PM	Coal,Gas,or Nos.1&2 F.O	8760	0.1 lb/MMBtu	N/A	N/A	242.8	1,063.45	40 CFR 60.42(a)1&2	**C.4**
	(Acid Rain Phase II Unit)	SO_2	Coal	8760	1.2 lb /MMBtu	N/A	N/A	2,913.6	12,761.57	40 CFR 60.43(a)&(c)	**C.5**
	(Acid Rain Phase I Unit)	SO_2	Nos.1 and 2 F.O.	8760	0.8 lb /MMBtu	N/A	N/A	1,942.4	8,507.71	40 CFR 60.43(a)&(c)	**C.5**
		% sulfur	Coal	Maximum allowable sulfur content: 6.3×10^{-5} BTU per lb coal						PA74-04	**C.6**
		NOx	Coal	8760	0.7 lb /MMBtu	N/A	N/A	1,699.6	7,444.25	40 CFR60.44(a)&(b)	**C.8**
		NOx	Nos.1 and 2 F.O.	8760	0.3 lb /MMBtu	N/A	N/A	728.4	3,190.39	40 CFR60.44(a)&(b)	**C.8**
		NOx	Nat. Gas	8760	0.2 lb /MMBtu	N/A	N/A	485.60	2,126.92	40 CFR60.44(a)&(b)	**C.8**

* The "Equivalent Emissions" listed are for informational purposes.
F.O. = Fuel oil

Table 2-1, Summary of Compliance Requirements

City of Gainesville,GRU
Deerhaven Generating Station

PROPOSED Permit No.: 0010006-001-AV
Facility ID No.: 0010006

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	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date [2]	Min. Compliance Test Duration	CMS [1]	See Permit Condition(s)
003	Boiler No. 1	VE	Nos.1, 2, 4, 5, & No. 6 F.O.	DEP method 9	Annually [3]	31-Jan	60 Minutes	YES	**A.17, 18, 23, 25, 27 & 28**
			Natural Gas/propane	DEP method 9	N/A	N/A	N/A	YES	**A.28**
		PM	Nos. 1, 2, 4, 5,/No.6 F.O.	17, 5, 5B or 5F	Annually 3	31-Jan	60 minutes	No	**A.19., 22.-25, 27, & 29**
			Natural Gas/propane	17, 5, 5B or 5F	Annually 3	31-Jan	60 minutes	No	**A.29**
	Acid Rain Phase II Unit	As, Cd, Cr, Pb	Used Oil	SW-846					**A.11**
		Total Halogens	Used Oil	SW-846					**A.11**
		Flash Point	Used Oil	SW-846					**A.11**
		PCBs	Used Oil	SW-846					**A.11**
		SO_2	No. 6 F.O.	Fuel Sampling & Analysis				Yes	**A.15, 20, 21**
004	Incinerator - Type I Waste	VE	Type I Waste/Nat.Gas	DEP method 9				No	**B.12, 13, 15**
xxx	Coal Handling & Storage	VE		EPA method 9	N/A		30 Minutes		**E.8, E.11, & G.3**

Notes:

[1] CMS [=] continuous monitoring system.

[2] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

[3] Test not required in years that: only gaseous fuel is fired, gaseous fuel in combination with liquid fuel is fired for no more than 400 hours, other than during startup; only liquid for no more than 400 hours, other than during startup

Table 2-1A, Summary of Compliance Requirements

City of Gainesville,GRU
Deerhaven Generating Station

PROPOSED Permit No.: 0010006-001-AV
Facility ID No.: 0010006

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	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date [2]	Min. Compliance Test Duration	CMS [1]	See Permit Condition(s)
006	Combustion Unit 3	VE	Nos. 1 & 2 F.O./ Nat. Gas	EPA method 9	Annually[5,6]		30 Minutes	No	D.7, E.7, E.11
	74.4 MW	NOx	Nos. 1 & 2 F.O./ Nat. Gas	EPA method 20	Annually[6]		60 minutes	Yes	D.7
		SO_2/SAM	Nos. 1 & 2 F.O	ASTM 4057-88 and D2622-92, D4294-90, D2880-71or ASTM D129-91 (or equivalent)[4]				Yes	D.8, D.10, D.11, D.18
	Acid Rain	SO_2/SAM	Natural Gas					Yes	
	Phase II Unit	PM10	Nos. 1 & 2 F.O.	Fuel Sampling & Analysis - see SO_2/SAM methods					D.8, D.10, D.11, D.18
		PM	Natural Gas						
		Water-to-fuel	Nos. 1 & 2 F.O.	NOx -CEMS				Yes	D.13
005	Boiler No. 2	VE	Coal,Gas, or Nos. 1 & 2 F.O	EPA method 9	Annually[3]		60 Minutes	Yes	C.9, C.12, E.5, 7 & 8
	2,428 MMBtu/hr								
	Acid Rain	PM	Coal, Gas, or Nos. 1 & 2 F.O	EPA 17, 5, 5B or 5F	Annually[3]		60 minutes	No	C.9, C.12, E.6
	Phase I Unit	NOx	Coal, Gas, or Nos. 1 & 2 F.O	EPA 7,7A,7C,7D, 7E	Annually		60 minutes	Yes	C.9, C.12
	Phase II Unit	SO_2	Coal, Gas, or Nos. 1 & 2 F.O	EPA 6,6A,6C	Annually		60 minutes	Yes	C.9, C.12

[1] CMS [=] continuous monitoring system.

[2] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

[3] Test not required in years that: only gaseous fuel is fired; gaseous fuel in combination with liquid fuel is fired for no more than 400 hours other than during startup; only liquid fuel is fired for no more than 400 hours, other than during startup.

[4] Fuel analysis pursuant to 40 CFR 60.335 (e) (1993 version) and 40 CFR75.

[5] If a combustion turbine is operated less than 400 hours per year, test is only required once every 5 years, during the year prior to permit renewal.

[6] Test required for the fuel(s) used for more than 400 hours in the preceding 12-months.