NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit Renewal:

Mr. Randy L. Casserleigh	Permit Project No.: 0010006-003-AV
R.O., D.R. and Interim Assistant General Manager of Energy Supply	Deerhaven Generating Station
City of Gainesville - Gainesville Regional Utilities Deerhaven Generating Station Mowery Road, Building 82, University of Florida Gainesville, Florida 32611	Alachua County

Enclosed is the FINAL Title V Air Operation Permit Renewal, Project No. 0010006-003-AV. This Permit renewal is being issued to allow continued commercial operation of the facility; in addition, the Permit renewal incorporates the changes made through air construction (AC) permit (letter), Project No. 0010006-004-AC. This permit renewal is issued pursuant to Chapter 403, Florida Statutes (F.S.). There were no comments received from Region 4, U.S. EPA, regarding the PROPOSED Permit.

Any party to this order has the right to seek judicial review of the permit 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 Legal Office; 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 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

Title V Air Operation Permit Renewal Project No.: 0010006-003-AV

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL Determination and the FINAL Permit) was sent by certified mail before the close of business on 12/28/04 to the person(s) listed or as otherwise noted:

Mr. Randy L. Casserleigh, R.O., D.R. and Interim Assistant General Manager of Energy Supply, City of Gainesville, Gainesville Regional Utilities, Deerhaven Generating Station, 10001 NW 13th Street, Gainesville, Florida 32653

The undersigned duly designated deputy agency clerk hereby certifies that a copy of this NOTICE OF FINAL PERMIT was sent by U.S. Mail or e-mail before the close of business on 12/28/04 to the person(s) listed or as otherwise noted:

Mr. Thomas W. Davis, P.E., ECTI
Mr. Chris Kirts, NED
Mr. Hamilton "Buck" Oven, P.E., PPSA
U.S. EPA, Region 4

12/28/04 cc: Bruce Mitchell, Reading File

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.

Barbara J. Friday 12/28/04
(Clerk) (Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Randy L. Casserleigh
R.O.,D.R. and Interim Assistant General Manager of Energy Supply
City of Gainesville-Gainesville Regional Utilities
Deerhaven Generating Station
Mowery Road, Building 82, University of Florida
Gainesville, Florida 32611

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☒ Agent ☐ Addressee

B. Received by (*Printed Name*) C. Date of Delivery JAN - 3 20[illegible]

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If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
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OFFICIAL USE
Mr. Randy L. Casserleigh, R.O.,D.R.

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Sent To Mr. Randy L. Casserleigh, R.O.,D.R.
Street, Apt. No.; or PO Box No. Mowery Road, Building 82, U Of F
City, State, ZIP+4 Gainesville, Florida 32611

PS Form 3800, June 2002 See Reverse for Instructions

STATEMENT OF BASIS

FINAL Title V Air Operation Permit Renewal No.: **0010006-003-AV**
City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station
Alachua County

This Title V air operation permit renewal 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 initial Title V Air Operation Permit, No. 0010006-001-AV, was effective 01/01/2000. 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 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. Based on the Title V permit renewal application received July 2, 2004, this facility is a major source of hazardous air pollutants (HAPs). **Compliance Assurance Monitoring (CAM) applies to Unit 2.**

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. 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.

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. 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. **CAM applies to particulate matter.**

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. 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 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; and, amended on November 8, 2004. BACT limits were incorporated into the PSD permit, No. PSD-FL-212 (and, amended on November 8, 2004: see 0010006-005-AC/PSD-FL-212(A), and Power Plant Siting Act 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, which is required in accordance with 40 CFR 60, Subpart GG; also, the NO_x CEMS will be used for compliance. 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 permitting note related to potential-to-emit/capacity/heat input was not included for the Simple Cycle Combustion Turbine No. 3 (see Specific Condition C.1.), which was permitted under the rules for Prevention of Significant Deterioration in air construction permit, No. PSD-FL-212, and Power Plant Conditions of Certification (PPCC), PA 74-04. Information kept on site, internal operating procedures, historical data from the EPA Air Markets Website, and Department's standards for equipment and accuracy ensure that the emissions units will continue to operate within their permitted heat input limits. (See Rule 62-297.310(5), F.A.C.; also, see Specific Condition D.4.)

FINAL Determination

City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station

Title V Air Operation Permit Renewal No.: 0010006-003-AV

I. Comments.

No comments were received from the U.S. EPA, Region 4, during their 45 day review period of the PROPOSED Permit.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

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

Title V Air Operation Permit Renewal
FINAL Permit No.: 0010006-003-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: 850/488-0114
Fax: 850/922-9533

Compliance Authority:
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/807-3300
Fax: 904/448-4363

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FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

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

FINAL Permit No.: 0010006-003-AV
Facility ID No.: 0010006
SIC No.: 49; 4911
Project: Title V Air Operation Permit Renewal

This permit is for the renewal of the Title V air operation permit for the City of Gainesville, Gainesville Regional Utilities (GRU), Deerhaven Generating Station. 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.

This Title V air operation permit renewal 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-4, TITLE V CONDITIONS (version dated 02/12/2002)
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
ORDER CORRECTING SCRIVENER'S ERROR: ASP Number 97-B-01
Phase II Acid Rain Application dated/signed 06/21/2004
Phase II NO_x Compliance Plan dated/signed 06/25/2004
APPENDIX CAM

Effective Date: January 1, 2005
Renewal Application Due Date: July 5, 2009
Expiration Date: December 31, 2009

Michael G. Cooke, Director
Division of Air Resource Management

MGC/jkp/bm

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two steam boilers (Nos. 1 and 2); two steam turbines; three simple cycle combustion turbines (CT) designated Nos. 1, 2 and 3; 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 Title V permit renewal application received July 2, 2004, 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 No.	Brief Description
003	960 MMBtu/hr Steam Boiler No. 1
005	2,428 MMBtu/hr Steam Boiler No. 2
006	74 MW (nominal) Simple Cycle Combustion Turbine No. 3
007	Coal Handling and Storage Activities

Unregulated Emissions Units and/or Activities

E.U. ID No.	Brief Description
008	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>
Application for Permit Renewal received July 2, 2004.
E-mail from Yolanta E. Jonynas received August 30, 2004.
Letter received from Mr. Randy Casserleigh, R.O., via facsimile on September 27, 2004.
Proof of publication of the Public Notice received on November 1, 2004, via a facsimile.
Comments from Mr. Robert W. Klemans, P.E., with GRU, received November 5, 2004, via a facsimile.

Section II. Facility-wide Conditions.

The following Conditions apply facility-wide:

1. Appendix TV-4, Title V Conditions, is a part of this permit.
{Permitting note: Appendix TV-4, 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 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).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 1515
Lanham-Seabrook, MD 20703-1515
Telephone: 301/429-5018

and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant 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. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS):

The following requirements are "not federally enforceable":

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; and,
d. Confining abrasive blasting where possible and appropriate,

[Rule 62-296.320(4)(c)2., F.A.C.; and 0010006-001-AV]

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)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-4, TITLE V CONDITIONS)}

[Rules 62-213.440(3) and 62-213.900, 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: 904/807-3300
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

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.]

14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), 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 a 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, and propane (ignition). 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.**
[Rule 62-296.405(1)(a), F.A.C.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. 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**.
[Rule 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. Compliance with this specific condition shall be demonstrated using the recordkeeping requirements of Specific Condition **A.11.f.**, below.

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 ("batch" means the amount of used oil placed in inventory at one time):
(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) Sulfur content, percent by weight.
(4) 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. Recordkeeping 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, 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.11.e.(4)** and the total amount of on-specification used oil placed in inventory during the previous calendar year, even if the response is zero. 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.; and, 40 CFR 279 and 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. In lieu of Method 9 testing, a transmissometer utilizing a 6-minute block average for opacity measurement may be used, provided such transmissometer is installed, certified, calibrated, operated, and maintained in accordance with the provisions of 40 CFR Part 75. 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 parenthesies 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 exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee may elect 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 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 D2622-98, ASTM D4294-90, ASTM D4294-98, ASTM D1552-90, ASTM D4057-88 or 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. See Specific Condition **A.19**.
(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]

Recordkeeping 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. See **Appendix TV-4, Title V Conditions, Condition No. 9**.
[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 as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.

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

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

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
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. CAM applies to particulate matter.}

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).}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. 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.}

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

B.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.; and, PA 74-04]

Emission Limitations and Standards

B.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)]

B.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:

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

Where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired,
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)]

B.6. 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]

B.7. 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

B.8. 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, 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 **E.2.**]. Acceptable alternative methods and procedures are given in 40 CFR 60.46(d) [Specific Condition **B.8.(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 **B.4., 5.** and **7.**] 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 **B.8.(d)(1)**]:

$E = CF_d (20.9)/(20.9 - \% O_2)$

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 Specific Condition **B.8.(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 [Specific Condition **E.3.**] shall be used to determine opacity except as otherwise allowed under Specific Condition **E.3.(e)(5)**.

(4) Method 6 [or the methods specified in Specific Condition **B.8.(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 Specific Condition **B.8.(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 Specific Condition **B.8.(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) [Specific Conditions **B.5.** and **B.7.**] 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 [Specific Condition **B.8.**] 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 F_c factor, provided that the following procedure is used:

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

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

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 Specific Condition **B.8.(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) [Specific Condition **B.8.(b)**]. Then if F_o (average of three runs), as calculated from the equation in Method 3B [or Method 3A pursuant to Specific Condition **B.8.(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 F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

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

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

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

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

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

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46(d)(1) [Specific Condition **B.8.**].

(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)]

B.9. 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

B.10. 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 **E.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]

B.11. Annual Tests Required - PM, VE, SO_2 and NOx. Except as provided in Specific Conditions **D.5.** through **D.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.; and, Power Plant Certification: PA 74-04]

B.12. 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 **B.12.(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 **E.5.(c)**] and calibration checks under 40 CFR 60.13(d) [Specific Condition **E.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 **B.8.**].

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B, 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 **B.12.**] 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 **B.12.**] 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 **B.12.(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 **B.12.(f)**].

(f) The values used in the equations under 40 CFR 60.45(e)(1) and (2) [Specific Condition **B.12.**] 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 **B.12.**].
(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 *sub-bituminous 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 $F_c = 0.486 \times 10^{-7}$ 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 $F_c = 0.384 \times 10^{-7}$ 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, $F_c = 0.279 \times 10^{-7}$ 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 **B.12.**].

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

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

(SI units)

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

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

$$F_c = \frac{321 x 10^3 \ (\%C)}{GCV}$$
(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 **B.12.(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 semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Excess emission reports may be submitted on a quarterly basis at the permittee's discretion. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c) [Specific Condition **E.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 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 **B.5.**].
(3) Nitrogen oxides. Excess emissions 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 **B.7.**].

[40 CFR 60.45(g)]
Pursuant to 40 CFR 60.13(h) [Specific Condition **E.5.(h)**], 1-hour averages of SO_2 and NO_x shall be computed from four (4) or more data points equally spaced over each 1-hour period.

Other NSPS Subpart D Conditions

B.13. 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, 40 CFR 60.

Common Conditions

B.14. This emissions unit is also subject to Specific Conditions **D.1.** through **D.14.** contained in **Subsection D. NSPS Common Conditions.**

B.15. This emissions unit is also subject to Specific Conditions **E.1.** through **E.6.** contained in **Subsection E. NSPS General Conditions.**

Subsection C. 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-NO_x 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; and, amended on November 8, 2004. BACT limits were incorporated into the PSD permit, No. PSD-FL-212 (and, amended on November 8, 2004: see 0010006-005-AC/PSD-FL-212(A)), and Power Plant Siting Act 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, which is required in accordance with 40 CFR 60, Subpart GG; also, the NO_x CEMS will be used for compliance. 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

C.0. Hours of Operation. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.
[PSD-FL-212 and PA 74-04]

C.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.; and, PA 74-04 and PSD-FL-212]

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

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

C.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.; and, PSD-FL-212 and PA 74-04]

Emission Limitations and Standards

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

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

C.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 62-210.700, F.A.C., and the BACT analysis (including the amended BACT).

Pollutant	Fuel	BACT Standard
NO_x	Gas	15 ppmvd @ 15% Oxygen(a)
	Oil	42 ppmvd @ 15% Oxygen(a)
PM_{10}	Gas	Good combustion; VE shall not exceed 10% opacity (b)
	Oil	Good combustion of low sulfur fuel oil, max. 0.05% sulfur, by weight; VE shall not exceed 10% opacity (b)
		Good combustion; low sulfur fuel oil, max. 0.05% sulfur, by weight; VE shall not exceed 10% opacity (b)
SO_2	Gas	Good combustion (b)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight (b)
H_2SO_4 Mist	Gas	Good combustion (b)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight (b)

(a) The averaging time shall be based on the test method.
(b) Compliance shall be demonstrated through combustion of pipeline natural gas and fuel oil sulfur analysis.
(c) The NO_x CEMS will be used in lieu of water/fuel system monitoring and will be used for determining compliance with the NO_x standard.
[PA 74-04; PSD-FL-212; BACT; BACT, as amended; and, 0010006-004-AC and PSD-FL-212(A)]

Test Methods and Procedures

C.7. Annual Compliance Tests.
a. Visible Emissions. Except as otherwise provided in Specific Condition **D.7.** of this permit, emission testing for visible emissions shall be performed annually in accordance with Specific Condition **C.9.**, with the fuel(s) used for more than 400 hours in the preceding federal fiscal year. Tests shall be conducted using EPA Reference Method 9 in accordance with 40 CFR 60, Appendix A.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, PA 74-04 and PSD-FL-212]

b. Nitrogen Oxides. The annual calibration RATA (Relative Accuracy Test Audit) associated with the NO_X CEMS shall be performed annually in accordance with Specific Condition **C.9.** using EPA Reference Method 20 pursuant to 40 CFR 60, Appendix A, and includes all of the requirements of Rule 62-297.310, F.A.C., (i.e., prior test notification, proper test result submittal, etc.).
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; and, applicant request]

C.8. Testing for SO_2, PM_{10} and 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 SAM 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 **C.11**. for the sulfur content of liquid fuels.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; and, PA 74-04 and PSD-FL-212]

C.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]

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

C.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 **C.5.**, **C.6.**, and **C.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.; and, PA 74-04 and PSD-FL-212]

Monitoring of Operations

C.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]

C.13.a. Excess Emissions by CEMS. The CEMS for NO_x 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. An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds the BACT standards (15/42 gas/oil) and shall be reported as excess emissions in accordance with Specific Condition **E.5.(h)** and following the format of 40 CFR 60.7(c) [Specific Condition **E.1.(c)**]; and, a "4-hour rolling average NO_x concentration" is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15 percent O_2) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; 40 CFR 60.334(j)(1)(iii)(A); and, 0010006-004-AC and PSD-FL-212(A)]

b. Excess NO_x Emissions by CEMS. Excess NO_x emissions resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two (2) hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration.
[Rule 62-210.700(1), F.A.C.; and, PSD-FL-212 and PA 74-04]

c. NO_x CEMS for Continuous Compliance. The NO_x CEMS shall be used for continuous compliance.
[PSD-FL-212 and PA 74-04; 0010006-004-AC/PSD-FL-212(A); and, facsimile received 09/27/04 from Mr. Randy Casserleigh, R.O.]

C.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 NO_x emission rates shall be corrected to ISO conditions to demonstrate compliance with the NO_x 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]

C.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]

Recordkeeping and Reporting Requirements

C.16. Additional Reports Required. The owner or operator shall report the following with the Air Operating Report (AOR): sulfur 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.; and, PA 74-04 and PSD-FL-212]

C.17. Custom Fuel Monitoring Schedule. The sulfur 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 SO_2 emissions are measured using monitoring systems that have been certified by EPA in accordance with 40 CFR 75. Monitoring of the nitrogen content in the fuel oil is not required because the permit does not provide a fuel-bound nitrogen allowance for this emissions unit.]

Other Conditions

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

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

C.20. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY *
CO	Good combustion; and, proper use of water injection system	95.4
VOC	Good combustion	8.66
Inorganic Arsenic	Firing Natural Gas/Nos. 1 or 2 Fuel Oil	0.004854
Mercury	Firing Natural Gas/Nos. 1 or 2 Fuel Oil	0.0009
Lead	Firing Natural Gas/Nos. 1 or 2 Fuel Oil	0.05746
Beryllium	Firing Natural Gas/Nos. 1 or 2 Fuel Oil	0.00032

* TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO conditions for a total of 3900 hrs/yr, with up to 2000 hrs/yr of Nos. 1 or 2 fuel oil-fired operation.

Subsection D. NSPS Common Conditions.

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

The following Conditions apply to the emissions unit(s)/activities listed above except as noted below: Specific Conditions **D.1.**, **D.4.**, **D.5.**, **D.6.**, **D.7.**, **D.9.**, **D.10.**, **D.12.**, and **D.14.** *do not apply* to E.U. ID No. 007, Coal Handling and Storage Activities.

Essential Potential to Emit (PTE) Parameters

D.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.}

D.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.

[Permitting Note. For excess NO_x emissions for combustion turbine No. 3, please see Specific Condition **C.13.b.**]

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

D.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

D.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.}

D.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 **D.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 **D.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]

D.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.]

D.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 no more than 400 hours per year; or
c. only liquid fuel(s) for no more than 400 hours per year.

[Rule 62-4.070(3), F.A.C.]

D.8. Visible Emissions. The test method for visible emissions for emissions units 005 (Unit 2), 006 (CT3) and 007 (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 **E.3.(b)**.
[Rules 62-204.800 and 62-297.401, F.A.C.; Subpart Y; and, 40 CFR 60.254(b) and 60.11]

D.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]

D.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.]

D.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.]

D.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.]

Recordkeeping and Reporting Requirements

D.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. See **Appendix TV-4, Title V Conditions, Condition No. 9**.
[Rule 62-210.700(6), F.A.C.]

D.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 E. 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
007	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 **E.1.(a)(4)(c** through **e)**, **E.5.** and **E.6.** *do not apply* to E.U. ID. 007, Coal Handling and Storage Activities (see Subsection H):

E.1. Pursuant to 40 CFR 60.7: Notification And Recordkeeping.
(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 Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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 (e)(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 full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 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 <u>five</u> 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.]

E.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]

E.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) [Specific Condition **E.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) [Specific Condition **E.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]

E.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]

E.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, 40 CFR 60, and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F, 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) [Specific Condition **E.3.(e)(5)**], he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, 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) [Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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) [Specific Condition **E.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, 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 O_2 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]

E.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 F. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
007	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 Pt. 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.}

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

F.1. <u>Particulate matter emissions from the coal handling facilities.</u> The permittee 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

F.2. Visible Emissions. See Specific Condition **D.8**.

Other Conditions

F.3. These emissions units are also subject to Specific Conditions contained in **Subsection D. NSPS Common Conditions except as otherwise noted therein.**

F.4. These emissions units are also subject to Specific Conditions contained in **Subsection E. 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 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/signed 06/21/2004.
[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	2005	2006	2007	2008	2009
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. <u>Emission Allowances.</u> Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), 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 II.

The emissions unit listed below is regulated under Acid Rain Part, Phase II, for the City of Gainesville, Gainesville Regional Utilities, 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 II Acid Rain unit must comply with the standard requirements and special provisions set forth in the permit listed below:
a. Phase II NO_x Compliance Plan dated/signed 06/25/2004.
[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/signed June 25, 2004.

3. Comments, notes, and justifications: none.

Appendix H-1: Permit History

City of Gainesville
Gainesville Regional Utilities – Deerhaven Generating Station

FINAL Permit No.: 0010006-003-AV
Facility ID No.: 0010006

E.U. ID No.	Description	Permit No.	Effective Date [1]	Expiration Date	Project Type
All	Facility	0010006-001-AV	01/01/2000	12/31/2004	Initial
-003	Boiler No. 1	0010006-003-AV	01/01/2005	12/31/2009	Renewal[1]
-005	Boiler No. 2	0010006-002-AV	06/19/2002	12/31/2004	Revision
		0010006-003-AV	01/01/2005	12/31/2009	Renewal
-006	Combustion Turbine No. 3	0010006-003-AV	01/01/2005	12/31/2009	Renewal
		0010006-004-AC/PSD-FL-212(A)/PA 74-04	11/08/2004	12/3/12009	Construction (mod.)

[1] Change to an actual date, which is day 55 from the date of posting the PROPOSED Permit for EPA review (see confirmation e-mail from Tallahassee) or the date that EPA confirms resolvement of any objections; or, if Acid Rain, January 1 of a given year.

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

City of Gainesville, GRU
Deerhaven Generating Station

FINAL Permit No.: 0010006-003-AV
Facility ID No.: 0010006

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 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)]}

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

City of Gainesville, GRU — **FINAL Permit No.: 0010006-003-AV**
Deerhaven Generating Station — **Facility ID No.: 0010006**

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
008	Lime Silo
008	Soda Ash Silo
008	Brine Spray Dryer
008	Loading of Dried Brine to Trucks
008	Brine Trucks to Onsite Landfill, Full
008	Brine Trucks to Onsite Landfill, Empty
008	Unloading of Brine from Trucks to Onsite Landfill
008	Brine Landfill
008	Dozer Operations on Brine Landfill
008	Pneumatic Transfer of Fly Ash from DH-2 to Fly Ash Silo
008	Dry Transfer from Fly Ash Silo to Trucks (Vented to Baghouse)
008	Dry Transfer from Fly Ash Silo to Trucks (Fugitives)
008	Wet (Pug Mill) Transfer from Fly Ash Silo to Trucks (Fugitives)
008	Fly Ash Trucks to Onsite Landfill, Full
008	Fly Ash Trucks to Onsite Landfill, Empty
008	Fly Ash Trucks to Offsite Disposal, Full
008	Fly Ash Trucks to Offsite Disposal, Empty
008	Transfer of Wet Fly Ash from Trucks to Onsite Landfill
008	Dozer Operations on Fly Ash Landfill
008	Fly Ash Landfill
008	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)

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

City of Gainesville, GRU **FINAL Permit Renewal No.: 0010006-003-AV**
Deerhaven Generating Station **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		
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**
	0	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**
007	Coal Handling and Storage	VE		8760	Not to exceed 20% opacity			N/A	N/A	40 CFR 60.252.(c)	**F.1**

* 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 1-1, Summary of Air Pollutant Standards and Terms.

City of Gainesville, GRU FINAL Permit Renewal No.: 0010006-003-AV
Deerhaven Generating Station 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)
006	Combustion Turbine No. 3	VE	Nat. Gas	3900	10% Opacity			N/A	N/A	BACT	**C.4**
	74.4 MW	VE	Nos.1 and 2 F.O.	2000	10% Opacity			N/A	N/A	BACT	**C.4**
		NOx	Nat. Gas	3900	15 ppmvd @ 15 % Oxygen			58.0	113.0	BACT	**C.6**
		NOx	Nos.1 and 2 F.O.	2000	42 ppmvd @ 15 % Oxygen			184.0	184.0	BACT	**C.6**
		NOx	Gas/Nos. 1 & 2 F.O	1900/2000				combined	239.0	BACT	**C.6**
		SO_2	Gas	3900		29.0	57.0			BACT	**C.6**
	(Acid Rain Phase II Unit)	SO_2	Nos.1 and 2 F.O.	1900		53.0	53.0			BACT	**C.6**
		SO_2	Gas/Nos. 1 & 2 F.O	1900/2000	combined		81.0			BACT	**C.6**
		PM_{10}	Nat. Gas	3900		7.0	14.0			BACT	**C.6**
		PM_{10}	Nos.1 and 2 F.O.	2000		15.0	15.0			BACT	**C.6**
		PM_{10}	Gas/Nos. 1 & 2 F.O	1900/2000	combined		22.0			BACT	**C.6**
		SAM	Nat. Gas	3900		3.0	6.0			BACT	**C.6**
		SAM	Nos.1 and 2 F.O.	2000		6.0	6.0			BACT	**C.6**
		SAM	Gas/Nos. 1 & 2 F.O	1900/2000	combined		9.0			BACT	**C.6**
		% sulfur	Nat. Gas	10 grains/100 scf						BACT	**C.5**
		% sulfur	Nos.1 and 2 F.O.	0.05%, by wt.; *limited amount of 0.1%*						BACT	**C.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	**B.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	**B.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)	**B.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)	**B.5**
		NOx	Coal	8760	0.7 lb /MMBtu	N/A	N/A	1,699.6	7,444.25	40 CFR60.44(a)&(b)	**B.7**
		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)	**B.7**
		NOx	Nat. Gas	8760	0.2 lb /MMBtu	N/A	N/A	485.60	2,126.92	40 CFR60.44(a)&(b)	**B.7**

* 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

FINAL Permit Renewal No.: 0010006-003-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 4, 5	31-Jan	60 minutes	No	**A.19., 22.-25, 27, & 29**
			Natural Gas/propane	17, 5, 5B or 5F	Annually 4, 5	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**
007	Coal Handling & Storage	VE		EPA method 9	N/A		30 Minutes		**F.2**

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.
[4] 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
[5] Visible emission test must be concurrent with one particulate matter test run.
[6] Test not required.

Table 2-1, Summary of Compliance Requirements

City of Gainesville,GRU — **FINAL Permit Renewal No.: 0010006-003-AV**

Deerhaven Generating Station — **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[6, 7]		30 Minutes	No	**C.7**
	74.4 MW	NOx	Nos. 1 & 2 F.O./ Nat. Gas	EPA method 20	Annually[8]		60 Minutes[9]	Yes	**C.7 and C.13**
		SO_2/SAM	Nos. 1 & 2 F.O[5]	ASTM 4057-88 and D2622-92, D4294-90, D2880-71or ASTM D129-91 (or equivalent)					**C.8, C.10, C.11, C.18**
	Acid Rain	SO_2/SAM	Natural Gas[5]	ASTM D 1072-80, D3031-81, D4084-82, D4468-85, D5504-94 or D3246-81 (or equivalent)					**C.8, C.10, C.11, C.18**
	Phase II Unit	PM10	Nos. 1 & 2 F.O.	Fuel Sampling & Analysis - see SO_2/SAM methods					**C.8, C.10, C.11, C.18**
		PM	Natural Gas	Fuel Sampling & Analysis - see SO_2/SAM methods					**C.8, C.10, C.11, C.18**
		Water-to-fuel	Nos. 1 & 2 F.O.	NOx -CEMS				Yes	**C.13**
005	Boiler No. 2	VE	Coal,Gas, or Nos. 1 & 2 F.O	EPA method 9	Annually[3]		60 Minutes	Yes	**B.9, B.11**
	2,428 MMBtu/hr								
	Acid Rain	PM	Coal, Gas, or Nos. 1 & 2 F.O	EPA 17, 5, 5B or 5F	Annually[4]		60 minutes	No	**B.9, B.11**
	Phase I Unit	NOx	Coal, Gas, or Nos. 1 & 2 F.O	EPA 7,7A,7C,7D, 7E	Annually		60 minutes	Yes	**B.9, B.11**
	Phase II Unit	SO_2	Coal, Gas, or Nos. 1 & 2 F.O	EPA 6,6A,6C	Annually		60 minutes	Yes	**B.9, B.11**

[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.

[4] 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; only liquid fuel is fired for no more than 400 hours.

[5] Fuel analysis pursuant to 40 CFR 60.335(e) (1993 version) and 40 CFR 75.

[6] 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.

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

[8] Annual calibration RATA required for the NOx CEMS pursuant to 40 CFR Part 60 and Rule 62-297.310, F.A.C.

[9] EPA Reference Method 20 allows up to 4 hours to conduct a performance test pursuant to 40 CFR Part 60, Subpart GG.

APPENDIX CAM

Compliance Assurance Monitoring Requirements

Compliance Assurance Monitoring Requirements

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1. – 17. are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables, as submitted by the applicant and approved by the Department.

40 CFR 64.6 Approval of Monitoring.

1. The attached CAM plan(s), as submitted by the applicant, is/are approved for the purposes of satisfying the requirements of 40 CFR 64.3.
[40 CFR 64.6(a)]

2. The attached CAM plan(s) include the following information:
(i) The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
(ii) The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and
(iii) The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.
[40 CFR 64.6(c)(1)]

3. The attached CAM plan(s) describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see **CAM Conditions 5. - 9.**) and reporting exceedances or excursions (see **CAM Conditions 10. – 14.**).
[40 CFR 64.6(c)(2)]

4. The permittee is required to conduct the monitoring specified in the attached CAM plan(s) and shall fulfill the obligations specified in the conditions below (see **CAM Conditions 5. - 17.**).
[40 CFR 64.6(c)(3)]

40 CFR 64.7 Operation of Approved Monitoring.

5. Commencement of operation. The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit.
[40 CFR 64.7(a)]

6. Proper maintenance. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 CFR 64.7(b)]

7. Continued operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 64.7(c)]

8. Response to excursions or exceedances.

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) & (2)]

9. Documentation of need for improved monitoring. If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

[40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.

10. Based on the results of a determination made under **CAM Condition 8.a.**, above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with **CAM Condition 4.**, an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.

[40 CFR 64.8(a)]

11. Elements of a QIP:

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(i) Improved preventive maintenance practices.
(ii) Process operation changes.
(iii) Appropriate improvements to control methods.
(iv) Other steps appropriate to correct control performance.
(v) More frequent or improved monitoring (only in conjunction with one or more steps under **CAM Condition 11.b(i)** through **(iv)**, above).

[40 CFR 64.8(b)]

12. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

[40 CFR 64.8(c)]

13. Following implementation of a QIP, upon any subsequent determination pursuant to **CAM Condition 8.b.**, the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems; or
b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

[40 CFR 64.8(e)]

<u>40 CFR 64.9 Reporting And Recordkeeping Requirements.</u>

15. <u>General reporting requirements.</u>

a. On and after the date specified in **CAM Condition 5.** by which the owner or operator must use monitoring that meets the requirements of this appendix, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.
b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:
   (i) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
   (ii) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
   (iii) A description of the actions taken to implement a QIP during the reporting period as specified in **CAM Conditions 10.** through **14.** Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR 64.9(a)]

16. <u>General recordkeeping requirements.</u>

a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to **CAM Conditions 10.** through **14.**, and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions.

17. It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10]

Emissions Unit -005

**2,428 MMBtu/Hr Coal, Natural Gas and/or Distillate Fuel Oils (Nos. 1 & 2) Fired Boiler
Particulate Matter Emissions Controlled By ESP**

Monitoring Approach

	Indicator No. 1
I. Indicator	Stack opacity
Measurement Approach	The opacity is measured using a Continuous Opacity Monitoring System (COMS) in the stack downstream of the ESP.
II. Indicator Range	An excursion is defined as any one hour average measured stack opacity greater than 13%, excluding those events defined as startup/shutdown and malfunctions. An excursion will trigger an evaluation of the operation of the boiler and ESP. Corrective action will be taken as necessary.
III. Performance Criteria	
A. Data Representativeness	Opacity is related to the size and concentration of particles in the flue gas. As particulate mass emissions increase, it can be reasonably expected that stack opacity will also increase. The stack is equipped with a COMS that meets the installation and minimum acceptable accuracy requirements of 40 CFR Part 60, Performance Specification 1. The COMS is located downstream of the ESP and, therefore, reflects the performance of the primary particulate control device.
B. Verification of Operational Status	Not applicable. Monitoring approach uses existing equipment and procedures.
C. QA/QC Practices and Criteria	Daily zero and calibration drift check, periodic cleaning of optical surfaces and other periodic QA/QC checks as specified in the applicable version of Performance Specification 1.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	Six-minute averages are recorded by the DAHS. Daily reports with all six-minute averages are generated. One-hour averages are determined every six minutes from the average of the previous ten consecutive six-minute averages.
F. Averaging Period	The averaging period for opacity observations is a 6-minute block average.

BEST AVAILABLE COPY

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	6	9	7
Be			0.00022	0.00032	0.0004
Hg			0.0009	0.0009	0.1
Pb			0.05746	0.05740	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.

Date of Receipt of a BACT Application

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:

- Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- 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 [illegible]	[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:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
march 29, 1995 Date	April 11th, 1995 Date

Acid Rain Part Application

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

This submission is: ☐ New ☐ Revised Permit Renewal

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

Plant Name	Deerhaven	State	FL	ORIS Code	663

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
B1	Yes		
B2	Yes		
CT3	Yes	12/20/95	1/1/96
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

Plant Name (from Step 1)

STEP 3
Read the standard requirements

Acid Rain Part Requirements

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

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

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

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

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from Step 1)

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

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

STEP 4

Read the certification statement; sign, and date

Certification

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

Name Randy L. Casserleigh	
Signature	Date 6/21/04

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

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

This submission is: ☐ New ☐ Revised Permit Renewal

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	DEERHAVEN Plant Name	FL State	663 ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# B2 Type DBW	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☒	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☒	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☐	☐	☐	☐	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

BEST AVAILABLE COPY

STEP 3, cont'd.

Certification

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

Name Randy L. Casserleigh	
Signature	Date 6/25/04

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: • New • Revised (revised submissions must be complete; see instructions)

Permit Renewal

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

Plant Name	State	ORIS Code
Deerhaven	FL	663

STEP 2
Enter requested information for the designated representative.

Name	Randy L. Casserleigh
Address	Gainesville Regional Utilities P.O. Box 147117, A132 Gainesville, FL 32614-7117
Phone Number	352-334-3400 x1789
Fax Number	352-334-2786
E-mail address (if available)	casserleighrl@gru.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	Joe W. Shaw, Jr.
Phone Number	352-334-2600 x6240
Fax Number	352-334-2672
E-mail address (if available)	shawjw@gru.com

STEP 4: Complete Steps 5 and 6, read the certifications, sign and date.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

- I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
- Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1) Deerhaven	

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

Signature (designated representative)	Date 6/21/04
Signature (alternate designated representative)	Date 6/24/04

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit they own and/or operate.

Name City of Gainesville, d.b.a Gainesville Regional Utilities					● Owner	● Operator
ID# B1	ID# B2	ID# CT3	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					● Owner	● Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					● Owner	● Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

STEP 6
For any new affected units listed at STEP 5 that have not commenced commercial operation, enter the projected date on which the unit is expected to commence commercial operation.

ID#	Projected Commence Commercial Operation Date:
ID#	Projected Commence Commercial Operation Date:
ID#	Projected Commence Commercial Operation Date:
ID#	Projected Commence Commercial Operation Date: