TO: Howard Rhodes

FROM: Clair Fancy

SUBJECT: Title V FINAL Permit: 0010006-001-AV
Gainesville Regional Utilities: Deerhaven Generating Station

DATE: December 28, 1999

The attached initial Title V FINAL Permit is being issued for the operation of the Gainesville Regional Utilities – Deerhaven Generating Station, located in Alachua County, Florida. The facility operates two fossil fuel steam boilers (Boilers Nos. 1 & 2) and three simple cycle combustion turbines (DHCT Nos. 1 & 2: unregulated; and, DHCT No. 3: regulated). Boilers Nos. 1 & 2 and DHCT No. 3 are the Acid Rain Phase II Units for SO_2; also, Boiler No. 2 is an Early Election Phase I/II NOx Acid Rain Unit.

Objections and general comments were received from the U.S. EPA, Region 4, during the 45-day comment period. A letter to the USEPA dated December 23, 1999, resolved the objections and general comments, as reflected in the FINAL Determination. In a letter from Mr. Winston A. Smith, dated December 29, 1999, it was stated that the objections were resolved. Therefore, it is recommended that the attached Title V FINAL Permit be signed as changed.

CHF/bm

Attachment

cc: Scott Sheplak, P.E.

1/14/00
Final Permit

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

FINAL Permit No.: 0010006-001-AV
Gainesville Regional Utilities: Deerhaven Generating Station

Enclosed is FINAL Permit Number 0010006-001-AV for Gainesville Regional Utilities Deerhaven Generating Station located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) 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 permitting authority 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 permitting authority.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/14/00 to the person(s) listed or as otherwise noted:

Mr. Michael L. Kurtz *, General Manager/Responsible Official, GRU
Mr. Darrell R. DuBose, Designated Representative, GRU
Mr. Chris Kirts, P.E., NED
Mr. Gregg Worley, USEPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Elizabeth Bartlett, USEPA, Region 4 (INTERNET E-mail Memorandum)

1/14/00 cc: Bruce Mitchell
Reeding File

Clerk Stamp

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

Barbara J. Pontwell 1/14/00
(Clerk) (Date)

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

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

4a. Article Number
Z 094 212 728

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
JAN 18 2000

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X [signature]

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Z 094 212 728

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Mr. Michael L. Kurtz	
Street & Number P.O. Box 147117, Station A134	
Post Office, State, & ZIP Code Gainesville, FL 32614-7117	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 1/14/00 FINAL Permit No.:0010006-001-AV Gainesville Reg.-Deerhaven	

PS Form **3800**, April 1995

FINAL TITLE V PERMIT DETERMINATION

Gainesville Regional Utilities: Deerhaven Generating Station

FINAL Permit No.: 0010006-001-AV

I. Comment(s).

Objections and general comments were received from the USEPA (November 15, 1999 letter) during their 45 day review period of the PROPOSED permit. A letter from the Department was sent to Mr. Gregg Worley on December 23, 1999, as a formal response to the objections and general comments in an attempt to resolve the objections. In a letter from Mr. Winston A. Smith, dated December 29, 1999, it was stated that the objections have been resolved pursuant to the above referenced December 23, 1999 response letter. Therefore, the following responses to the objections and general comments are provided, in the order that they were received, and the appropriate changes to the permit will be made to resolve the objections and general comments.

A. EPA Objections.

1. Unit 1 is a SIP utility boiler regulated under Rule 62-296.405, F.A.C. Unit 1 combusts primarily natural gas, using residual fuel oil as a backup fuel on a limited basis as indicated below:

Year	Hours on Oil	Comments
1999	440	Through 11/99; gas curtailed
1998	234	
1997	301	
1996	262	
1995	277	

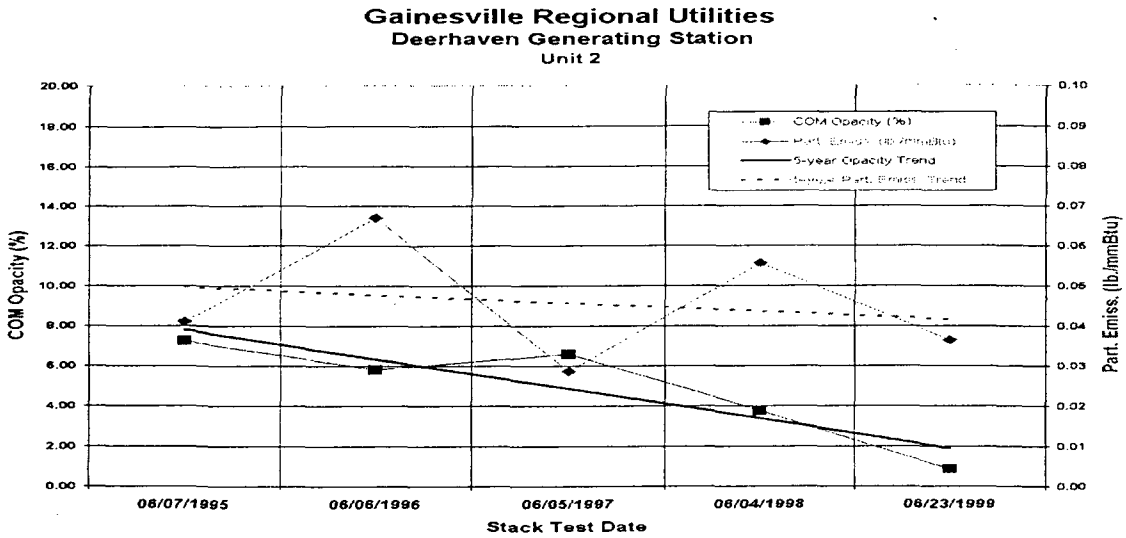
Unit 1 is subject to a steady-state PM emission limit of 0.1 lb/MMBtu and a soot-blowing emission limit of 0.3 lb/MMBtu. PM testing conducted in 1996 indicated PM emission rates of 0.071 and 0.068 lb/MMBtu under steady-state and soot-blowing conditions, respectively. The Department believes that these rates are sufficiently below the standard to justify annual testing.

Unit 2 is a coal-fired boiler with a 20% opacity limit and a 0.1 lb/MMBtu particulate matter limit. The table below presents PM test results and contemporaneous COMs data for 1995 – 1999.

	Non-sootblowing						Sootblowing		Combined	
	Run 1		Run 2		Avg. of Run 1 & 2				Avg. of All Runs	
Date	COM Opacity (%)	Part. Emiss. (lb./mmBtu)	COM Opacity (%)	Part. Emiss. (lb./mmBtu)	COM Opacity (%)	Part. Emiss. (lb./mmBtu)	COM Opacity (%)	Part. Emiss. (lb./mmBtu)	COM Opacity (%)	Part. Emiss. (lb./mmBtu)
06/07/1995	7.08	0.03100	7.04	0.02700	7.06	0.02900	7.57	0.06500	7.23	0.04100
06/06/1996	5.00	0.02200	5.30	* **0.10000**	5.15	0.06100	7.13	0.07900	5.81	0.06700
06/05/1997	6.42	0.02890	5.83	0.03030	6.13	0.02960	7.50	0.02680	6.58	0.02867
06/04/1998	4.36	0.06300	2.80	0.06200	3.58	0.06250	4.06	0.04200	3.74	0.05567
06/23/1999	0.93	0.03070	0.45	0.03680	0.69	0.03375	1.26	0.04160	0.88	0.03637
Average	—	—	—	—	4.52	0.04317	5.50	0.05088	**4.85**	**0.04574**

*** This result is suspected to be incorrect considering the result from Run 1 and historical information.**

As this table indicates, the particulate matter and opacity emissions are well below the permitted limits and trending downwards as shown in the figure below. The Department believes this data justifies annual testing for Unit 2.



2. Specific Conditions **A.8**, **A.9**, **C.4**, **C.5** and **C.8** will be revised to specify an averaging time of three (3) hours.

3 & 4. These comments address conditions imposed on the incinerator. GRU has decided to take the incinerator out-of-service. All references to the incinerator (Section III. Subsection B) will be deleted from the Title V permit and all subsequent Subsections will be renamed (Subsections C thru G <u>to</u> Subsections B thru F).

5. Specific Condition **D.1.** will be revised to remove the language pertaining to recordkeeping as follows:

{Permitting note:....~~Regular recordkeeping is not required for heat input. Instead, t~~The owner or operator...during the test.}

6. Specific Condition **D.4.** imposes an visible emission limitation on DHCT3. Specific Condition **D.7.** requires an annual EPA Method 9 to demonstrate compliance with this limitation whenever liquid fuel is burned for 400 hours or more.

DHCT3 combusts primarily natural gas, using distillate fuel oil as a backup fuel on a minimal basis as indicated below:

Year	Hours on Oil	Comments
1999	6.3	Through November 1999
1998	5.8	
1997	1.4	
1996	47	Includes 30 hrs for startup testing

Visible emission testing conducted in April 1996 while firing fuel oil indicated an opacity of 0%.

The Department believes that the annual testing frequency is justified by the low historical operational use of fuel oil and the previous VE test that indicated an opacity of zero which is well below the 10% standard. However, upon triggering the 400 hours of operation on fuel oil, GRU is willing to conduct additional VE testing every 400 hours of operation on fuel oil thereafter, in any given federal fiscal year.

7. Revision of Specific Condition **D.6.**, as suggested by EPA, is acceptable to the Department.

8. Specific Condition 8 in PSD-FL-212 addresses "estimated potential emissions" for CO, VOC, inorganic arsenic, mercury, lead and beryllium from CT3. As the footnote to this table specifies, the ton per year values were included for "annual operation reports (AOR) and PSD applicability determinations". This condition was included for information purposes only and does not impose emission limitations on these pollutants. Accordingly, no annual emission fees are assessed on these emissions and no monitoring or recordkeeping is required.

In order to impose any limits and subsequent compliance testing requirements, both EPA and the Department need to have an applicable rule requirement. Since these pollutants in question did not trigger the PSD NSR thresholds that would require a BACT determination, then neither EPA nor the Department have the legal authority or mechanism to impose any restriction on these pollutants. These pollutants were just listed in the permit because they are emitted from the process and have potential emissions, nothing more. Also, there are no specific emission limiting standards for these pollutants contained in our regulations and the federal regulations. If you wish, we can list the pollutants in the Title V permit document in the same manner as in the PSD permit. See Specific Condition **D.20** (new).

9. Historically, the visible emissions from the coal handling and storage systems have been less than 5% opacity. Specifically, by letters dated June 28, 1995 and December 2, 1996, GRU submitted to the Department visible emissions (VE) test data that indicated the VE observations ranged from zero to just over four percent, and were thus well below the 20% opacity limit imposed on these sources. Visible emission observations conducted by the Department were consistent with these results. Also, there have been no complaints concerning any particulate matter fallout from the two subdivisions located adjacent (across the highway). On this basis, the Department believes that it is appropriate to only impose the SIP requirement of annual Method 9 testing for these sources.

10. GRU requests, and the Department concurs, that Specific Condition **G.1.** be deleted, because there is no regulatory basis for it; and, all subsequent Specific Conditions will be renumbered.

11. The Department agrees with EPA's comment. The permit document will be corrected.

B. General Comments.

1. Comment has been noted.

2. Although the requirements for some of the emission units are contained in several different sections of the permit, the cross-references provided in the permit sections allow for an adequate interpretation of the permit.

3. Unit 1 was placed in commercial operation in August 1972. Historical files indicated that DAWPC Construction Permit No. AC280 was issued in April 23, 1970; and, contracts for the purchase of major equipment were executed in the late 1960s.

4. GRU has decided to take the incinerator out-of-service.

5. The Department concurs with EPA's suggestion.

6. The Department concurs with EPA's suggestion, but Facility-wide Condition 10 references Appendix TV-3, specifically condition 51, which provides the requirements of 40 CFR 70.6(c)(5)(iii).

7. The permit conditions that address excess emissions are based on regulations contained in FDEP's approved State Implementation Plan. The referenced conditions have been issued accordingly.

8. GRU suggests, and the Department concurs, that the evaluation of the sulfur content of used oil be addressed in Specific Condition **A.11.e.** with the other testing requirements as follows:

"A.11.e. Testing Requirements:...
(1) Arsenic...
(2) Testing...
(3) Sulfur content, percent by weight
(4) Alternatively,..."

9. GRU refers to a "batch" as the amount of used oil that is placed in inventory at one time; and, the following parenthetical expression will be added to the introductory statement:

....parameters ("batch" means the amount of used oil placed in inventory at one time):

10. GRU suggests, and the Department concurs, that Specific Condition **A.25.(b)** be revised to include a cross-reference to Specific Condition **A.19.** as follows:

"**A.25**....
(b) Minimum Sample Volume. Unless...cubic feet. See Specific Condition A.19."

11. Comment noted and will be addressed by correcting the typographical errors in Specific Condition **C.5.(b)**.

12. GRU requests, and the Department concurs, that Specific Condition **C.6.** be deleted from the permit because CEMS are in-place to measure sulfur dioxide emissions; and, all subsequent Specific Conditions will be renumbered.

13. The hours of operation for combustion turbine No. 3 are already included in Specific Condition **D.6.** Boiler No. 2 is not restricted with respect to hours of operation (i.e., it is allowed to operate 8,760 hours/year).

II. Conclusion.

In conclusion, the changes that have been made are insignificant in nature and do not impose additional noticing requirements. The permitting authority hereby issues the FINAL Title V permit, with any changes noted above.

STATEMENT OF BASIS

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

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, 62-213, and 62-214, F.A.C. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

The facility consists of two steam boilers (Unit Nos. 1 and 2) and associated steam turbines; an NSPS simple cycle combustion turbine (CT No. 3); two unregulated simple cycle combustion turbines (CT Nos. 1 and 2); a 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.

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

Unit 1 is a SIP utility boiler that combusts primarily natural gas, using residual fuel oil as a backup fuel on a limited basis as indicated below:

Year	Hours on Oil	Comments
1999	440	Through 11/99; gas curtailed
1998	234	
1997	301	
1996	262	
1995	277	

Unit 1 is subject to a steady-state PM emission limit of 0.1 lb/MMBtu and a soot-blowing emission limit of 0.3 lb/MMBtu. PM testing conducted in 1996 indicated PM emission rates of 0.071 and 0.068 lb/MMBtu under steady-state and soot-blowing conditions, respectively. The Department believes that these rates are sufficiently below the standard to justify annual testing.

Boiler No. 2.

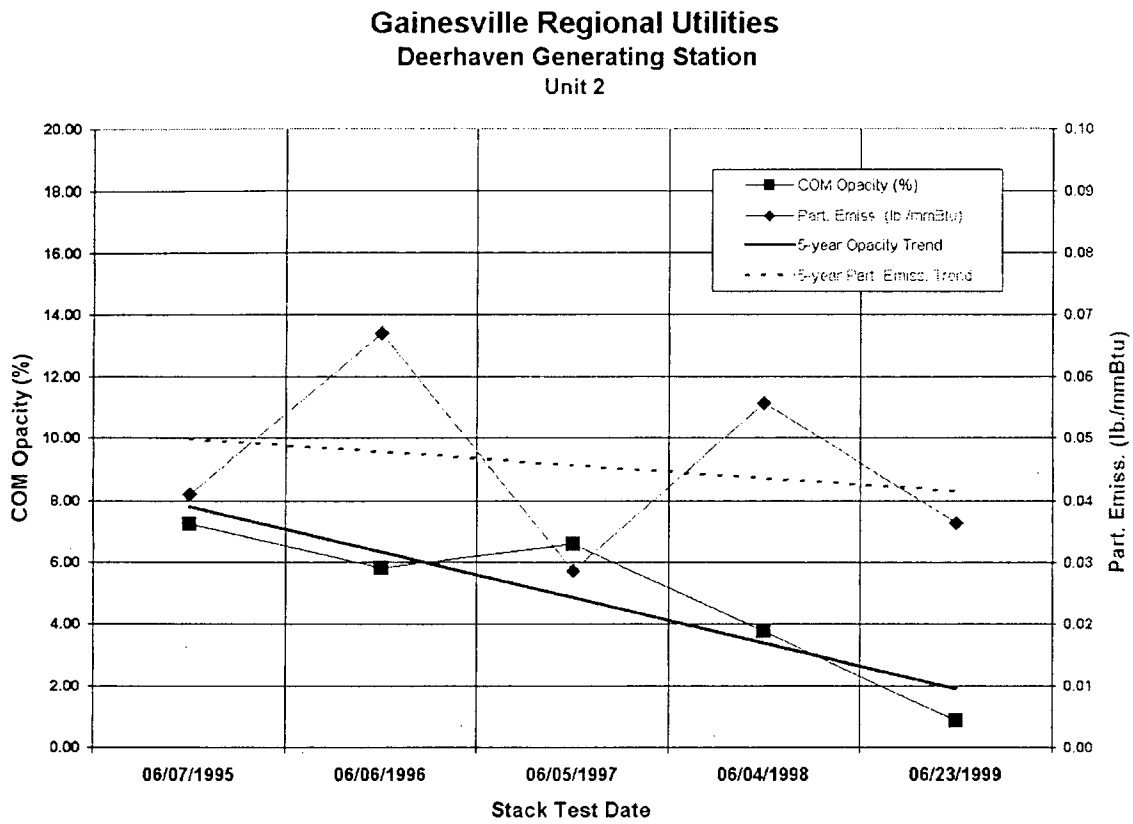
Fossil fuel fired steam generator No. 2 is rated at 251 MW (nominal) and is capable of burning coal, natural gas, or distillate fuel oils (Nos. 1 or 2), with emissions exhausted through a 350 ft. stack. Particulate matter emissions are controlled by an electrostatic precipitator. SO_2 emissions are minimized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

Unit 2 is a coal-fired boiler with a 20% opacity limit and a 0.1 lb/MMBtu particulate matter limit. The table below presents PM test results and contemporaneous COMs data for 1995 – 1999.

	Non-sootblowing						Sootblowing		Combined Avg. of All Runs	
	Run 1		Run 2		Avg. of Run 1 & 2					
Date	COM Opacity (%)	Part. Emiss. (lb/mmBtu)	COM Opacity (%)	Part. Emiss. (lb/mmBtu)	COM Opacity (%)	Part. Emiss. (lb/mmBtu)	COM Opacity (%)	Part. Emiss. (lb/mmBtu)	COM Opacity (%)	Part. Emiss. (lb/mmBtu)
06/07/1995	7.08	0.03100	7.04	0.02700	7.06	0.02900	7.57	0.05500	7.23	0.04100
06/06/1996	5.00	0.02200	5.30	* **0.10000**	5.15	0.06100	7.13	0.07900	5.81	0.06700
06/05/1997	6.42	0.02890	5.83	0.03030	6.13	0.02960	7.50	0.02680	6.58	0.02867
06/04/1998	4.36	0.06300	2.80	0.06200	3.58	0.06250	4.06	0.04200	3.74	0.05567
06/23/1999	0.93	0.03070	0.45	0.03680	0.69	0.03375	1.26	0.04160	0.88	0.03637
Average	—	—	—	—	4.52	0.04317	5.50	0.05088	**4.85**	**0.04574**

*** This result is suspected to be incorrect considering the result from Run 1 and historical information.**

As this table indicates, the particulate matter and opacity emissions are well below the permitted limits and trending downwards as shown in the figure below. The Department believes this data justifies annual testing for Unit 2.



Combustion Turbine No. 3.

Combustion turbine No. 3 is rated at 74 MW (nominal), 990.6 MMBtu/hr for distillate fuel oils (Nos. 1 or 2) and 971.1 MMBtu/hr for natural gas, with emissions exhausted through a 52 ft. stack. Emissions are controlled by dry low-NOx combustors when firing natural gas, and by water injection when firing fuel oil. The combustion turbine began commercial operation in 1995. This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. This unit underwent a BACT Determination dated April 11, 1995. BACT limits were incorporated into the PSD permit, No. PSD-FL-212, and Power Plant Conditions of Certification (PPCC), PA 74-04. These limitations are more stringent than the NSPS SO_2 and NO_x limitations and thus assure compliance with 40 CFR 60.332, 60.333 and 60.334. As required under the Acid Rain Program, the emissions unit has a continuous emission monitoring system (CEMS) for NO_x, SO_2, and CO_2. The NO_x CEMS is used in lieu of the water/fuel monitoring and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent and thus assures compliance with 40 CFR 60.334 and 60.335.

DHCT3 combusts primarily natural gas, using distillate fuel oil as a backup fuel on a minimal basis as indicated below:

Year	Hours on Oil	Comments
1999	6.3	Through November 1999
1998	5.8	
1997	1.4	
1996	47	Includes 30 hrs for startup testing

Visible emission testing conducted in April 1996 while firing fuel oil indicated an opacity of 0%.

The Department believes that the annual testing frequency is justified by the low historical operational use of fuel oil and the previous VE test that indicated an opacity of zero which is well below the 10% standard. However, upon triggering the 400 hours of operation on fuel oil, GRU is willing to conduct additional VE testing every 400 hours of operation on fuel oil thereafter, in any given federal fiscal year.

Coal Handling and Storage Activities.

Historically, the visible emissions from the coal handling and storage systems have been less than 5% opacity. Specifically, by letters dated June 28, 1995 and December 2, 1996, GRU submitted to the Department visible emissions (VE) test data that indicated the VE observations ranged from zero to just over four percent, and were thus well below the 20% opacity limit imposed on these sources. Visible emission observations conducted by the Department were consistent with these results. Also, there have been no complaints concerning any particulate matter fallout from the two subdivisions located adjacent (across the highway). On this basis, the Department believes that it is appropriate to only impose the SIP requirement of annual Method 9 testing for these sources.

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

City of Gainesville
Gainesville Regional Utilities
Deerhaven Generating Station
Facility ID No.: 0010006
Alachua County
Initial Title V Air Operation Permit
FINAL Permit No.: 0010006-001-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4363

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

TABLE OF CONTENTS

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

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

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

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

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, 62-213, and 62-214, F.A.C. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced Attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-3, TITLE V CONDITIONS (version dated 4/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (version dated 7/96)
BACT Determination dated 04/11/95
Alternate Sampling Procedure: ASP Number 97-B-01, including the Order Correcting the Scrivener's Error dated July 2, 1997
Phase II Acid Rain Application/Compliance Plan originally dated 12/22/95, and amended 1/9/96.
Phase I Acid Rain permit (NO_x Early Election) dated 12/13/96
Phase II NO_x Compliance Plan dated 12/19/97

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

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/sms/tbc

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two steam boilers (Nos. 1 and 2); two steam turbines; one simple cycle combustion turbine (CT) designated No. 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 initial Title V permit application received June 14, 1996, this facility is a major source of hazardous air pollutants (HAPs).

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

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

Unregulated Emissions Units and/or Activities

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

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

Subsection C. Relevant Documents.

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

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

These documents are on file with the permitting authority:
Initial Title V Permit Application received June 14, 1996.
Phase II Acid Rain Application/Compliance Plan originally dated 12/22/95, and amended 1/9/96.
Phase I Acid Rain permit (NO_x Early Election) dated 12/13/96
Phase II NO_x Compliance Plan dated 12/19/97
Revised DRAFT Title V Permit clerked 6/17/99

Section II. Facility-wide Conditions.

The following Conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:
a. a risk management plan (RMP) when, and if, such requirement becomes applicable; and,
b. certification forms and/or RMPs according to the promulgated rule schedule.
[40 CFR 68]

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

6. Insignificant Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

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

8. **Not federally enforceable.** Reasonable Precautions. The following techniques shall be used to control unconfined particulate matter emissions on an as needed basis:
a. Chemical or water application to unpaved road and unpaved yard and landfill areas;
b. Paving and maintenance of roads, parking areas and yards;
c. Landscaping or planting of vegetation;
d. Confining abrasive blasting where possible and appropriate,
[Rule 62-296.320(4)(c)2., F.A.C.]

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

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

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

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

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

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

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

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

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

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

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

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

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates, based on the higher heating value (HHV) of the fuel, are as follows:

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

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.] .

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

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **A.23**.
[Rule 62-297.310(2), F.A.C.].

A.3. Methods of Operation - Fuels. The only fuels allowed to be burned are distillate fuel oils (Nos. 1 or 2), residual fuel oils (Nos. 4, 5, or 6), natural gas, propane, and/or on-specification used oil, or any combination thereof. Used oil containing a PCB concentration equal to or greater than 50 ppm shall *not* be burned. Used oil containing PCBs above the detectable level (2 ppm) cannot be used for startup or shutdown.
[Rule 62-213.410, F.A.C.;and 40 CFR 761.20(e)] .

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

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Except as otherwise specified in this permit, this emissions unit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. See Specific Condition **A.29.**
[Rules 62-296.405(1)(a), F.A.C.]

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

A.7. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.8. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, minimum three (3) - hour average, as measured by applicable compliance methods. See Specific Condition **A.19.**
[Rules 62-296.405(1)(b) F.A.C.]

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

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

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

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

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

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

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

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

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

g. Reporting Requirements:

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

Excess Emissions

A.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

A.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.15. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See Specific Conditions **A.20.** and **A.21.**
[Rule 62-296.405(1)(f)1.b., F.A.C.]

A.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods And Procedures

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

A.17. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See Specific Condition **A.18.**
[Rule 62-296.405(1)(e)1., F.A.C.]

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

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

A.19. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.20. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedances of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee may elect to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel anlysis provided by the vendor or the permittee upon delivery.** See Specific Conditions **A.15.** and **A.21.**
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.]

A.21. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, ASTM D1552-90, ASTM 4177-82 or both, ASTM D4057-88 and ASTM D129-91, or the latest edition of the above ASTM methods.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.22. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three

complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

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

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

A.25. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur.
a. The minimum period of observation for a compliance test for Unit 1 is 60 minutes.
Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet. 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.]

Record keeping and Reporting Requirements

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

A.31. Submit to the Northeast District office a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.32. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Northeast District office on the results of each such test.
(b) The required test report shall be filed with the Northeast District office soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

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

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

Periodic Monitoring

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

Subsection B. This section addresses the following emissions unit.

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

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

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

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

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

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.; 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 of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46 [this Specific Condition], except as provided in 40 CFR 60.8(b) [Specific Condition **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)**]:

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

E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
% O_2 = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particulate matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems. [Alternatively Method 17 may be used pursuant to Condition **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 [Condition **E.3.**] shall be used to determine opacity except as otherwise allowed under Condition G.3.(e)(5).

(4) Method 6 [or the methods specified in Condition **C.9.(d)(3)**] shall be used to determine the SO_2 concentration.

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

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 [or the methods specified in Condition **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 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) [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 [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 Fc factor, provided that the following procedure is used:

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

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

where:
E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
$\%CO_2$ = carbon dioxide concentration, percent dry basis.
F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B [or Method 3A pursuant to Condition **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) [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 Condition D.9.(d)(7))], is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209\,(F_{da} / F_{ca})$, then the following procedure shall be followed:

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

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

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

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

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

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

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

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46 (d)(1) [Condition **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.; 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 to 40 CFR 60 [incorporated by reference].

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows except as otherwise specified in 40 CFR 75:

[In parts per million]

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

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45 (c)(3) [Specific Condition **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 *subbituminous and bituminous coal* as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/million Btu) and $F_c = 0.486 \times 10^{-7}$ 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 = 0.384×10^{-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)

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

(English units)

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

(SI units)

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

(English units)

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)

(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 for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c) [Specific Condition **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 for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43 [Specific Condition **B.5.**].

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44 [Specific Condition **B.7.**].

[40 CFR 60.45(g)]

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

Other NSPS Subpart D Conditions

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 of 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-NOx combustors when firing natural gas, and by water injection when firing fuel oil. The combustion turbine began commercial operation in 1996.

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

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

Essential Potential to Emit (PTE) Parameters

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

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

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

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.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.]

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 62-204.800(7), F.A.C., and the BACT analysis.

Pollutant	Fuel	BACT Standard	Lbs/Hr	TPY
NO_x*	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined (c)	239
PM_{10}	Gas	Good combustion; VE shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur fuel oil, max. 0.05% sulfur, by weight; VE shall not exceed 10% opacity	15(d)	15(b)(d)
		Good combustion; low sulfur fuel oil, max. 0.05% sulfur, by weight; VE shall not exceed 10% opacity	Combined (c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight	53(d) Combined(c)	53(b)(d) 81
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil; max. 0.05% sulfur content, by weight	6(d) Combined(c)	6(b)(d) 9

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

Test Methods and Procedures

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

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

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

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

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

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 NOx emission rates shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212; and, applicant request]

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]

Record Keeping and Reporting Requirements

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

C.17. Custom Fuel Monitoring Schedule. The sulfur and nitrogen content of the fuel oil being fired in the combustion turbine shall be determined in accordance with this schedule. Monitoring of the nitrogen and sulfur content in natural gas is *not* required.
a. Fuel oil: On each occasion that fuel oil is transferred to the storage tank from another source.
b. Natural gas: Not required.
The records of natural gas and distillate fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.
[PA 74-04 and PSD-FL-212; and, Applicant's Request]

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

Other Conditions

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 Condition **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/No. 2 Fuel Oil	0.004854
Mercury	Firing Natural Gas/No. 2 Fuel Oil	0.0009
Lead	Firing Natural Gas/No. 2 Fuel Oil	0.05746
Beryllium	Firing Natural Gas/No. 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 No. 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
xxx	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. xxx, 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.
[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 **E.7.**

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours (applicable to Unit 2 only). See Specific Condition **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 less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

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

D.8. Visible Emissions. The test method for visible emissions for emissions units 005 (Unit2), 006 (CT3) and xxx (Coal Handling and Storage Activities), shall be EPA Method 9, (adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.) or as otherwise provided in Specific Condition **E.3.(b)**.
[Rules 62-204.800 and 62-297.401, F.A.C.; Subpart Y, 40 CFR 60.254 (b) and 40 CFR 60.11]

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.]

Record Keeping 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.

[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
xxx	Coal Handling and Storage Activities

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

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

E.1. Pursuant to 40 CFR 60.7 Notification And Record Keeping.
(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:
(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
(b) The owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
(c) The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d) and Condition **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) [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) [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) [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 (3) (2) of this section.

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

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

(f) The owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

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) [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) [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 of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
(b) Not applicable.
(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11 (e)(5) [Condition **E.3.(e)(5)**], he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.
(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11 .(e)(5) [Condition **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) [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) [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) [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) [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) [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 of 40 CFR 60 shall be used.

(g) Not applicable.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[40 CFR 60.13]

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
xxx	Coal Handling and Storage Activities

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

SUMMARY OF COAL HANDLING ACTIVITIES:

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

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

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

Essential Potential to Emit (PTE) Parameters

F.1. Particulate matter emissions from the coal handling facilities. The permitee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading system processing coal, visible emissions which exceed 20 percent opacity.
[40 CFR 60. 252 (c) and Power Plant Certification PA 74-04]

Test Methods and Procedures

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(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II Acid Rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. Phase II Permit Application (DEP Form No. 62-210.900(1)(a)), dated 12/22/95, and amended 1/9/96.
b. Letter dated January 9, 1996 amending the original application (see Specific Condition **1.a.**, above).
c. Letter dated January 26, 1996 correcting DEP's unit designation for CT3 on the State of Florida Acid Rain Facilities table contained in the application completeness determination.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

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

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

3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

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

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

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

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

The emissions unit listed below is regulated under Acid Rain Part, Phase I/II, for City of Gainesville, GRU, Deerhaven Generating Station.

Facility ID No.: 0010006
ORIS code: 0663

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

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

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

E.U. ID No.	EPA ID	NO_x limit*
005	B2	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_x early election compliance plan for **unit B2**. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of **0.50 lb/mmBtu**" for **dry bottom wall-fired boilers**. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall **not** be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of **0.46 lb/mmBtu**" for **dry bottom wall-fired boilers** until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and the requirements covering excess emissions.

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

3. Comments, notes, and justifications: none.

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

City of Gainesville, GRU
Deerhaven Generating Station

FINAL Permit No.: 0010006-001-AV

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

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

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

City of Gainesville, GRU
Deerhaven Generating Station

FINAL Permit No.: 0010006-001-AV

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 TV-3, TITLE V CONDITIONS (version dated 04/30/99)

[Note: This attachment includes "canned conditions" developed from the "Title V Core List."]

{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

Chapter 62-4, F.A.C.

1. Not federally enforceable. General Prohibition. Any stationary installation which will reasonably be expected to be a source of pollution shall not be operated, maintained, or modified without the appropriate and valid permits issued by the Department, unless the source is exempted by Department rule. The Department may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit.
[Rule 62-4.030, Florida Administrative Code (F.A.C.); Section 403.087, Florida Statute (F.S.)]

2. Not federally enforceable. Procedure to Obtain Permits: Application.
(1) Any person desiring to obtain a permit from the Department shall apply on forms prescribed by the Department and shall submit such additional information as the Department by law may require.
(2) All applications and supporting documents shall be filed in quadruplicate with the Department.
(3) To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. All applications for a Department permit shall be certified by a professional engineer registered in the State of Florida except when the application is for renewal of an air pollution operation permit at a minor facility as defined in Rule 62-210.200, F.A.C., or where professional engineering is not required by Chapter 471, F.S. Where required by Chapter 471 or 492, F.S., applicable portions of permit applications and supporting documents which are submitted to the Department for public record shall be signed and sealed by the professional(s) who prepared or approved them.
(4) Processing fees for air construction permits shall be in accordance with Rule 62-4.050(4), F.A.C.
(5)(a) To be considered by the Department, each application must be accompanied by the proper processing fee. The fee shall be paid by check, payable to the Department of Environmental Protection. The fee is non-refundable except as provided in Section 120.60, F.S., and in this section.
(c) Upon receipt of the proper application fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin.
(d) If the applicant does not submit the required fee within ten days of receipt of written notification, the Department shall either return the unprocessed application or arrange with the applicant for the pick up of the application.
(e) If an applicant submits an application fee in excess of the required fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin upon receipt, and the Department shall refund to the applicant the amount received in excess of the required fee.
(6) Any substantial modification to a complete application shall require an additional processing fee determined pursuant to the schedule set forth in Rule 62-4.050, F.A.C., and shall restart the time requirements of Sections 120.60 and 403.0876, F.S. For purposes of this Subsection, the term "substantial modification" shall mean a modification which is reasonably expected to lead to substantially different environmental impacts which require a detailed review.
(7) Modifications to existing permits proposed by the permittee which require substantial changes in the existing permit or require substantial evaluation by the Department of potential impacts of the proposed modifications shall require the same fee as a new application.
[Rule 62-4.050, F.A.C.]

3. Standards for Issuing or Denying Permits. Except as provided at Rule 62-213.460, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules.
[Rule 62-4.070(7), F.A.C.]

4. Modification of Permit Conditions.

(1) For good cause and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions and on application of the permittee the Department may grant additional time. For the purpose of this section, good cause shall include, but not be limited to, any of the following: (also, see Condition No. 38)

(a) A showing that an improvement in effluent or emission quality or quantity can be accomplished because of technological advances without unreasonable hardship.

(b) A showing that a higher degree of treatment is necessary to effect the intent and purpose of Chapter 403, F.S.

(c) A showing of any change in the environment or surrounding conditions that requires a modification to conform to applicable air or water quality standards.

(e) Adoption or revision of Florida Statutes, rules, or standards which require the modification of a permit condition for compliance.

(2) A permittee may request a modification of a permit by applying to the Department.

(3) A permittee may request that a permit be extended as a modification of the permit. Such a request must be submitted to the Department in writing before the expiration of the permit. Upon timely submittal of a request for extension, unless the permit automatically expires by statute or rule, the permit will remain in effect until final agency action is taken on the request. For construction permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that, upon completion, the extended permit will comply with the standards and conditions required by applicable regulation. For all other permits, an extension shall be granted if the applicant can demonstrate reasonable assurances that the extended permit will comply with the standards and conditions applicable to the original permit. A permit for which the permit application fee was prorated in accordance with Rule 62-4.050(4)(1), F.A.C., shall not be extended. In no event shall a permit be extended or remain in effect longer than the time limits established by statute or rule.

[Rule 62-4.080, F.A.C.]

5. Renewals. Prior to one hundred eighty (180) days before the expiration of a permit issued pursuant to Chapter 62-213, F.A.C., the permittee shall apply for a renewal of a permit using forms incorporated by reference in the specific rule chapter for that kind of permit. A renewal application shall be timely and sufficient. If the application is submitted prior to 180 days before expiration of the permit, it will be considered timely and sufficient. If the renewal application is submitted at a later date, it will not be considered timely and sufficient unless it is submitted and made complete prior to the expiration of the operation permit. When the application for renewal is timely and sufficient, the existing permit shall remain in effect until the renewal application has been finally acted upon by the Department or, if there is court review of the Department's final agency action, until a later date is required by Section 120.60, F.S., provided that, for renewal of a permit issued pursuant to Chapter 62-213, F.A.C., the applicant complies with the requirements of Rules 62-213.420(1)(b)3. and 4., F.A.C.

[Rule 62-4.090(1), F.A.C.]

6. Suspension and Revocation.

(1) Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.

(2) Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.

(3) A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or the permit holder's agent:

(a) Submitted false or inaccurate information in application or operational reports.

(b) Has violated law, Department orders, rules or permit conditions.

(c) Has failed to submit operational reports or other information required by Department rules.

(d) Has refused lawful inspection under Section 403.091, F.S.

[Rule 62-4.100, F.A.C.]

7. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules.

[Rule 62-4.110, F.A.C.]

8. Transfer of Permits.
(1) Within 30 days after the sale or legal transfer of a permitted facility, an "Application for Transfer of Permit" (DEP Form 62-1.201(1)) must be submitted to the Department. This form must be completed with the notarized signatures of both the permittee and the proposed new permittee.
(2) The Department shall approve the transfer of a permit unless it determines that the proposed new permittee cannot provide reasonable assurances that conditions of the permit will be met. The determination shall be limited solely to the ability of the new permittee to comply with the conditions of the existing permit, and it shall not concern the adequacy of these permit conditions. If the Department proposes to deny the transfer, it shall provide both the permittee and the proposed new permittee a written objection to such transfer together with notice of a right to request a Chapter 120, F.S., proceeding on such determination.
(3) Within 30 days of receiving a properly completed Application for Transfer of Permit form, the Department shall issue a final determination. The Department may toll the time for making a determination on the transfer by notifying both the permittee and the proposed new permittee that additional information is required to adequately review the transfer request. Such notification shall be served within 30 days of receipt of an Application for Transfer of Permit form, completed pursuant to Rule 62-4.120(1), F.A.C. If the Department fails to take action to approve or deny the transfer within 30 days of receipt of the completed Application for Transfer of Permit form, or within 30 days of receipt of the last item of timely requested additional information, the transfer shall be deemed approved.
(4) The permittee is encouraged to apply for a permit transfer prior to the sale or legal transfer of a permitted facility. However, the transfer shall not be effective prior to the sale or legal transfer.
(5) Until this transfer is approved by the Department, the permittee and any other person constructing, operating, or maintaining the permitted facility shall be liable for compliance with the terms of the permit. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility.
[Rule 62-4.120, F.A.C.]

9. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. (also, see Condition No. 10)
[Rule 62-4.130, F.A.C.]

10. For purposes of notification to the Department pursuant to Condition No. 9, Condition No. 12(8), and Rule 62-4.130, F.A.C., Plant Operation-Problems, "immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of 40 CFR 70.6(a)(3)(iii)(B), "prompt" shall have the same meaning as "immediately". [also, see Conditions Nos. 9 and 12(8)]
[40 CFR 70.6(a)(3)(iii)(B)]

11. Not federally enforceable. Review. Failure to request a hearing within 14 days of receipt of notice of proposed or final agency action on a permit application or as otherwise required in Chapter 62-103, F.A.C., shall be deemed a waiver of the right to an administrative hearing.
[Rule 62-4.150, F.A.C.]

12. Permit Conditions. All permits issued by the Department shall include the following general conditions:
(1) The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
(2) This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
(3) As provided in subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit.

(4) This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
(5) This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.
(6) The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
(7) The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:

(a) Have access to and copy any records that must be kept under conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
(c) Sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.

(8) If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information: (also, see Condition No. 10)

(a) A description of and cause of noncompliance; and,
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

(9) In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
(10) The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
(11) This permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
(12) This permit or a copy thereof shall be kept at the work site of the permitted activity.
(14) The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
(c) Records of monitoring information shall include:

1. the date, exact place, and time of sampling or measurements;
2. the person responsible for performing the sampling or measurements;
3. the dates analyses were performed;
4. the person responsible for performing the analyses;
5. the analytical techniques or methods used; and,
6. the results of such analyses.

(15) When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.
[Rules 62-4.160 and 62-213.440(1)(b), F.A.C.]

13. Construction Permits.
(1) No person shall construct any installation or facility which will reasonably be expected to be a source of air or water pollution without first applying for and receiving a construction permit from the Department unless exempted by statute or Department rule. In addition to the requirements of Chapter 62-4, F.A.C., applicants for a Department Construction Permit shall submit the following as applicable:

(a) A completed application on forms furnished by the Department.
(b) An engineering report covering:
1. plant description and operations,
2. types and quantities of all waste material to be generated whether liquid, gaseous or solid,
3. proposed waste control facilities,
4. the treatment objectives,
5. the design criteria on which the control facilities are based, and,
6. other information deemed relevant.

Design criteria submitted pursuant to Rule 62-4.210(1)(b)5., F.A.C., shall be based on the results of laboratory and pilot-plant scale studies whenever such studies are warranted. The design efficiencies of the proposed waste treatment facilities and the quantities and types of pollutants in the treated effluents or emissions shall be indicated. Work of this nature shall be subject to the requirements of Chapter 471, F.S. Where confidential records are involved, certain information may be kept confidential pursuant to Section 403.111, F.S.

(c) The owners' written guarantee to meet the design criteria as accepted by the Department and to abide by Chapter 403, F.S. and the rules of the Department as to the quantities and types of materials to be discharged from the installation. The owner may be required to post an appropriate bond or other equivalent evidence of financial responsibility to guarantee compliance with such conditions in instances where the owner's financial resources are inadequate or proposed control facilities are experimental in nature.

(2) The construction permit may contain conditions and an expiration date as determined by the Secretary or the Secretary's designee.
(3) When the Department issues a permit to construct, the permittee shall be allowed a period of time, specified in the permit, to construct, and to operate and test to determine compliance with Chapter 403, F.S., and the rules of the Department and, where applicable, to apply for and receive an operation permit. The Department may require tests and evaluations of the treatment facilities by the permittee at his/her expense.
[Rule 62-4.210, F.A.C.]

14. Not federally enforceable. Operation Permit for New Sources. To properly apply for an operation permit for new sources, the applicant shall submit certification that construction was completed noting any deviations from the conditions in the construction permit and test results where appropriate.
[Rule 62-4.220, F.A.C.]

Chapters 28-106 and 62-110, F.A.C.

15. Public Notice, Public Participation, and Proposed Agency Action. The permittee shall comply with all of the requirements for public notice, public participation, and proposed agency action pursuant to Rule 62-110.106 and Rule 62-210.350, F.A.C.
[Rules 62-110.106, 62-210.350 and 62-213.430(1)(b), F.A.C.]

16. Administrative Hearing. The permittee shall comply with all of the requirements for a petition for administrative hearing or waiver of right to administrative proceeding pursuant to Rules 28-106.201, 28-106.301 and 62-110.106, F.A.C.
[Rules 28-106.201, 28-106.301 and 62-110.106. , F.A.C.]

Chapter 62-204, F.A.C.

17. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR Part 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source.
[40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

Chapter 62-210, F.A.C.

18. Permits Required. The owner or operator of any emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, modification, or initial or continued operation of the emissions unit unless exempted pursuant to Department rule or statute. All emissions limitations, controls, and other requirements imposed by such permits shall be at least as stringent as any applicable limitations and requirements contained in or enforceable under the State Implementation Plan (SIP) or that are otherwise federally enforceable. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law.

(1) Air Construction Permits.

(a) Unless exempt from permitting pursuant to Rule 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., an air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification, in accordance with all applicable provisions of this chapter, Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C. Except as provided under Rule 62-213.415, F.A.C., the owner or operator of any facility seeking to create or change an air emissions bubble shall obtain an air construction permit in accordance with all the applicable provisions of this chapter, Chapter 62-212, F.A.C., and Chapter 62-4, F.A.C. The construction permit shall be issued for a period of time sufficient to allow construction or modification of the facility or emissions unit and operation while the new or modified facility or emissions unit is conducting tests or otherwise demonstrating initial compliance with the conditions of the construction permit.

(b) Notwithstanding the expiration of an air construction permit, all limitations and requirements of such permit that are applicable to the design and operation of the permitted facility or emissions unit shall remain in effect until the facility or emissions unit is permanently shut down, except for any such limitation or requirement that is obsolete by its nature (such as a requirement for initial compliance testing) or any such limitation or requirement that is changed in accordance with the provisions of Rule 62-210.300(1)(b)1., F.A.C. Either the applicant or the Department can propose that certain conditions be considered obsolete. Any conditions or language in an air construction permit that are included for informational purposes only, if they are transferred to the air operation permit, shall be transferred for informational purposes only and shall not become enforceable conditions unless voluntarily agreed to by the permittee or otherwise required under Department rules.

1. Except for those limitations or requirements that are obsolete, all limitations and requirements of an air construction permit shall be included and identified in any air operation permit for the facility or emissions unit. The limitations and requirements included in the air operation permit can be changed, and thereby superseded, through the issuance of an air construction permit, federally enforceable state air operation permit, federally enforceable air general permit, or Title V air operation permit; provided, however, that:

a. Any change that would constitute an administrative correction may be made pursuant to Rule 62-210.360, F.A.C.;

b. Any change that would constitute a modification, as defined at Rule 62-210.200, F.A.C., shall be accomplished only through the issuance of an air construction permit; and

c. Any change in a permit limitation or requirement that originates from a permit issued pursuant to 40 CFR 52.21, Rule 62-204.800(10)(d)2., F.A.C., Rule 62-212.400, F.A.C., Rule 62-212.500, F.A.C., or any former codification of Rule 62-212.400 or 62-212.500, F.A.C., shall be accomplished only through the issuance of a new or revised air construction permit under Rule 62-204.800(10)(d)2., F.A.C., 62-212.400 or 62-212.500, F.A.C., as appropriate.

2. The force and effect of any change in a permit limitation or requirement made in accordance with the provisions of Rule 62-210.300(1)(b)1. F.A.C., shall be the same as if such change were made to the original air construction permit.

3. Nothing in Rule 62-210.300(1)(b), F.A.C., shall be construed as to allow operation of a facility or emissions unit without a valid air operation permit.

(2) Air Operation Permits. Upon expiration of the air operation permit for any existing facility or emissions unit, subsequent to construction or modification and demonstration of initial compliance with the conditions of the construction permit for any new or modified facility or emissions unit, or as otherwise provided in Chapter 62-210 or Chapter 62-213, the owner or operator of such facility or emissions unit shall obtain a renewal air operation permit, an initial air operation permit, or an administrative correction or revision of an existing air operation permit, whichever is appropriate, in accordance with all applicable provisions of Chapter 62-210, Chapter 62-213, and Chapter 62-4, F.A.C.

(a) Minimum Requirements for All Air Operation Permits. At a minimum, a permit issued pursuant to this subsection shall:

1. Specify the manner, nature, volume and frequency of the emissions permitted, and the applicable emission limiting standards or performance standards, if any;

2. Require proper operation and maintenance of any pollution control equipment by qualified personnel, where applicable in accordance with the provisions of any operation and maintenance plan required by the air pollution rules of the Department.

3. Contain an effective date stated in the permit which shall not be earlier than the date final action is taken on the application and be issued for a period, beginning on the effective date, as provided below.

a. The operation permit for an emissions unit which is in compliance with all applicable rules and in operational condition, and which the owner or operator intends to continue operating, shall be issued or renewed for a five-year period, except that, for Title V sources subject to Rule 62-213.420(1)(a)1., F.A.C., operation permits shall be extended until 60 days after the due date for submittal of the facility's Title V permit application as specified in Rule 62-213.420(1)(a)1., F.A.C.

b. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for six months or more prior to the expiration date of the current operation permit, shall be renewed for a period not to exceed five years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided:

(i) the owner or operator of the emissions unit demonstrates to the Department that the emissions unit may need to be reactivated and used, or that it is the owner's or operator's intent to apply to the Department for a permit to construct a new emissions unit at the facility before the end of the extension period; and,

(ii) the owner or operator of the emissions unit agrees to and is legally prohibited from providing the allowable emission permitted by the renewed permit as an emissions offset to any other person under Rule 62-212.500, F.A.C.; and,

(iii) the emissions unit was operating in compliance with all applicable rules as of the time the source was shut down.

c. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for five years or more prior to the expiration date of the current operation permit shall be renewed for a maximum period not to exceed ten years from the date of shutdown, even if the emissions unit is not maintained in operational condition, provided the conditions given in Rule 62-210.300(2)(a)3.b., F.A.C., are met and the owner or operator demonstrates to the Department that failure to renew the permit would constitute a hardship, which may include economic hardship.

d. The operation permit for an electric utility generating unit on cold standby or long-term reserve shutdown shall be renewed for a five-year period, and additional five-year periods, even if the unit is not maintained in operational condition, provided the conditions given in Rules 62-210.300(2)(a)3.b.(i) through (iii), F.A.C., are met.

4. In the case of an emissions unit permitted pursuant to Rules 62-210.300(2)(a)3.b., c., and d., F.A.C., include reasonable notification and compliance testing requirements for reactivation of such emissions unit and provide that the owner or operator demonstrate to the Department prior to reactivation that such reactivation would not constitute reconstruction pursuant to Rule 62-204.800(7), F.A.C.

[Rules 62-210.300(1) & (2), F.A.C.]

19. Not federally enforceable. Notification of Startup. The owner or operator of any emissions unit or facility which has a valid air operation permit and which has been shut down more than one (1) year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of sixty (60) days prior to the intended startup date.

(a) The notification shall include the planned startup date, anticipated emission rates or pollutants released, changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.

(b) If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

20. Emissions Unit Reclassification.

(a) Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.

(b) If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit. [Rule 62-210.300(6), F.A.C.]

21. Public Notice and Comment.

(1) Public Notice of Proposed Agency Action.

(a) A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant for:

1. An air construction permit;

2. An air operation permit, permit renewal or permit revision subject to Rule 62-210.300(2)(b), F.A.C., (i.e., a FESOP), except as provided in Rule 62-210.300(2)(b)1.b., F.A.C.; or

3. An air operation permit, permit renewal, or permit revision subject to Chapter 62-213, F.A.C., except those permit revisions meeting the requirements of Rule 62-213.412(1), F.A.C.

(b) The notice required by Rule 62-210.350(1)(a), F.A.C., shall be published in accordance with all otherwise applicable provisions of Rule 62-110.106, F.A.C. A public notice under Rule 62-210.350(1)(a)1., F.A.C., for an air construction permit may be combined with any required public notice under Rule 62-210.350(1)(a)2. or 3., F.A.C., for air operation permits. If such notices are combined, the public notice must comply with the requirements for both notices.

(c) Except as otherwise provided at Rules 62-210.350(2) and (5), F.A.C., each notice of intent to issue an air construction permit shall provide a 14-day period for submittal of public comments.

(2) Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment - Area Preconstruction Review.

(a) Before taking final agency action on a construction permit application for any proposed new or modified facility or emissions unit subject to the preconstruction review requirements of Rule 62-212.400 or 62-212.500, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S., and the Department's analysis of the effect of the proposed construction or modification on ambient air quality, including the Department's preliminary determination of whether the permit should be approved or disapproved;

2. A 30-day period for submittal of public comments; and,

3. A notice, by advertisement in a newspaper of general circulation in the county affected, specifying the nature and location of the proposed facility or emissions unit, whether BACT or LAER has been determined, the degree of PSD increment consumption expected, if applicable, and the location of the information specified in paragraph 1. above; and notifying the public of the opportunity for submitting comments and requesting a public hearing.

(b) The notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.

(c) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall also be sent by the Department to the Regional Office of the U. S. Environmental Protection Agency and to all other state and local officials or agencies having cognizance over the location of such new or modified facility or emissions unit, including local air pollution control agencies, chief executives of city or county government, regional land use planning agencies, and any other state, Federal Land Manager, or Indian Governing Body whose lands may be affected by emissions from the new or modified facility or emissions unit.

(d) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be displayed in the appropriate district, branch and local program offices.

(e) An opportunity for public hearing shall be provided in accordance with Chapter 120, F.S., and Rule 62-110.106, F.A.C.

(f) Any public comments received shall be made available for public inspection in the location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., is available and shall be considered by the Department in making a final determination to approve or deny the permit.

(g) The final determination shall be made available for public inspection at the same location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., was made available.

(h) For a proposed new or modified emissions unit which would be located within 100 kilometers of any Federal Class I area or whose emissions may affect any Federal Class I area, and which would be subject to the preconstruction review requirements of Rule 62-212.400, F.A.C., or Rule 62-212.500, F.A.C.:

1. The Department shall mail or transmit to the Administrator a copy of the initial application for an air construction permit and notice of every action related to the consideration of the permit application.

2. The Department shall mail or transmit to the Federal Land Manager of each affected Class I area a copy of any written notice of intent to apply for an air construction permit; the initial application for an air construction permit, including all required analyses and demonstrations; any subsequently submitted information related to the application; the preliminary determination and notice of proposed agency action on the permit application; and any petition for an administrative hearing regarding the application or the Department's proposed action. Each such document shall be mailed or transmitted to the Federal Land Manager within fourteen (14) days after its receipt by the Department.

(3) Additional Public Notice Requirements for Facilities Subject to Operation Permits for Title V Sources.

(a) Before taking final agency action to issue a new, renewed, or revised air operation permit subject to Chapter 62-213, F.A.C., the Department shall comply with all applicable provisions of Rule 62-110.106, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S.; and,

2. A 30-day period for submittal of public comments.

(b) The notice provided for in Rule 62-210.350(3)(a), F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-110.106, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.

(c) The notice shall identify:

1. The facility;

2. The name and address of the office at which processing of the permit occurs;

3. The activity or activities involved in the permit action;

4. The emissions change involved in any permit revision;

5. The name, address, and telephone number of a Department representative from whom interested persons may obtain additional information, including copies of the permit draft, the application, and all relevant supporting materials, including any permit application, compliance plan, permit, monitoring report, and compliance statement required pursuant to Chapter 62-213, F.A.C. (except for information entitled to confidential treatment pursuant to Section 403.111, F.S.), and all other materials available to the Department that are relevant to the permit decision;

6. A brief description of the comment procedures required by Rule 62-210.350(3), F.A.C.;

7. The time and place of any hearing that may be held, including a statement of procedure to request a hearing (unless a hearing has already been scheduled); and,

8. The procedures by which persons may petition the Administrator to object to the issuance of the proposed permit after expiration of the Administrator's 45-day review period.

[Rule 62-210.350, F.A.C.]

22. Administrative Permit Corrections.

(1) A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:

(a) Typographical errors noted in the permit;

(b) Name, address or phone number change from that in the permit;

(c) A change requiring more frequent monitoring or reporting by the permittee;

(d) Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;

(e) Changes listed at 40 CFR 72.83(a)(11), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(d), F.A.C.; and

(f) Any other similar minor administrative change at the source.

(2) Upon receipt of any such notification the Department shall within 60 days correct the permit and provide a corrected copy to the owner.

(3) After first notifying the owner, the Department shall correct any permit in which it discovers errors of the types listed at Rule 62-210.360(1)(a) and (b), F.A.C., and provide a corrected copy to the owner.

(4) For Title V source permits, other than general permits, a copy of the corrected permit shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

(5) The Department shall incorporate requirements resulting from issuance of a new or revised construction permit into an existing Title V source permit, if the construction permit or permit revision incorporates requirements of federally enforceable preconstruction review, and if the applicant requests at the time of application that all of the requirements of Rule 62-213.430(1), F.A.C., be complied with in conjunction with the processing of the construction permit application.
[Rule 62-210.360, F.A.C.]

23. Reports.
(3) Annual Operating Report for Air Pollutant Emitting Facility.
(a) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year.
(c) The annual operating report shall be submitted to the appropriate Department District or Department approved local air pollution control program office by March 1 of the following year unless otherwise indicated by permit condition or Department request.
[Rule 62-210.370(3), F.A.C.]

24. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
[Rule 62-210.650, F.A.C.]

25. Forms and Instructions. The forms used by the Department in the stationary source control program are adopted and incorporated by reference in this section. The forms are listed by rule number, which is also the form number, with the subject, title and effective date. Forms 62-210.900(1),(3),(4) and (5), F.A.C., including instructions, are available from the Department as hard-copy documents or executable files on computer diskettes. Copies of forms (hard-copy or diskette) may be obtained by writing to the Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Notwithstanding the requirement of Rule 62-4.050(2), F.A.C., to file application forms in quadruplicate, if an air permit application is submitted using the Department's electronic application form, only one copy of the diskette and signature pages is required to be submitted.
(1) Application for Air Permit - Title V Source, Form and Instructions (Effective 2-11-99).
(a) Acid Rain Part (Phase II), Form and Instructions (Effective 7-1-95).
1. Repowering Extension Plan, Form and Instructions (Effective 7-1-95).
2. New Unit Exemption, Form and Instructions (Effective 7-1-95).
3. Retired Unit Exemption, Form and Instructions (Effective 7-1-95).
4. Phase II NOx Compliance Plan, Form and Instructions (Effective 1-6-98).
5. Phase II NOx Averaging Plan, Form (Effective 1-6-98).
(b) Reserved.
(5) Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions (Effective 2-11-99).
[Rule 62-210.900, F.A.C.]

Chapter 62-213, F.A.C.

26. Annual Emissions Fee. Each Title V source permitted to operate in Florida must pay between January 15 and March 1 of each year, upon written notice from the Department, an annual emissions fee in accordance with Rule 62-213.205, F.A.C., and the appropriate form and associated instructions.
[Rules 62-213.205 and 62-213.900(1), F.A.C.]

27. Annual Emissions Fee. Failure to pay timely any required annual emissions fee, penalty, or interest constitutes grounds for permit revocation pursuant to Rule 62-4.100, F.A.C.
[Rule 62-213.205(1)(g), F.A.C.]

28. Annual Emissions Fee. Any documentation of actual hours of operation, actual material or heat input, actual production amount, or actual emissions used to calculate the annual emissions fee shall be retained by the owner for a minimum of five (5) years and shall be made available to the Department upon request.
[Rule 62-213.205(1)(j), F.A.C.]

29. Annual Emissions Fee. A completed DEP Form 62-213.900(1), F.A.C., "Major Air Pollution Source Annual Emissions Fee Form", must be submitted by the responsible official with the annual emissions fee.
[Rule 62-213.205(1)(k), F.A.C.]

30. Air Operation Permit Fees. After December 31, 1992, no permit application processing fee, renewal fee, modification fee or amendment fee is required for an operation permit for a Title V source.
[Rule 62-213.205(4), F.A.C.]

31. Permits and Permit Revisions Required. All Title V sources are subject to the permit requirements of Chapter 62-213, F.A.C.
(1) No Title V source may operate except in compliance with Chapter 62-213, F.A.C.
(2) Except as provided in Rule 62-213.410, F.A.C., no source with a permit issued under the provisions of this chapter shall make any changes in its operation without first applying for and receiving a permit revision if the change meets any of the following:
(a) Constitutes a modification;
(b) Violates any applicable requirement;
(c) Exceeds the allowable emissions of any air pollutant from any unit within the source;
(d) Contravenes any permit term or condition for monitoring, testing, recordkeeping, reporting or of a compliance certification requirement;
(e) Requires a case-by-case determination of an emission limitation or other standard or a source specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapters 62-212 or 62-296, F.A.C.;
(f) Violates a permit term or condition which the source has assumed for which there is no corresponding underlying applicable requirement to which the source would otherwise be subject;
(g) Results in the trading of emissions among units within a source except as specifically authorized pursuant to Rule 62-213.415, F.A.C.
(h) Results in the change of location of any relocatable facility identified as a Title V source pursuant to paragraph (a)-(e), (g) or (h) of the definition of "major source of air pollution" at Rule 62-210.200, F.A.C
(i) Constitutes a change at an Acid Rain Source under the provisions of 40 CFR 72.81(a)(1),(2),or (3),(b)(1) or (b)(3), hereby incorporated by reference;
(j) Constitutes a change in a repowering plan, nitrogen oxides averaging plan, or nitrogen oxides compliance deadline extension at an Acid Rain Source.
(k) Is a request for exemption pursuant to Rule 62-214.340, F.A.C.
[Rule 62-213.400(1) & (2), F.A.C.]

32. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation in each alternative method of operation:
(1) Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;
(2) Permitted sources may implement the terms or conditions of a new or revised construction permit if;
(a) The application for construction permit complied with the requirements of Rule 62-213.420(3) and (4), F.A.C.;
(b) The terms or conditions were subject to federally enforceable preconstruction review pursuant to Chapter 62-212, F.A.C.; and,
(c) The new or revised construction permit was issued after the Department and the applicant complied with all the requirements of Rule 62-213.430(1), F.A.C.;
(3) A permitted source may implement operating changes after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
(a) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
(b) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
(4) Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.
[Rule 62-213.410, F.A.C.]

33. Immediate Implementation Pending Revision Process.
(1) Those permitted Title V sources making any change that constitutes a modification pursuant to the definition of modification at Rule 62-210.200, F.A.C., but which would not constitute a modification pursuant to 42 USC 7412(a) or to 40 CFR 52.01, 60.2, or 61.15, adopted and incorporated by reference at Rule 62-204.800, F.A.C., may implement such change prior to final issuance of a permit revision in accordance with this section, provided the change:
(a) Does not violate any applicable requirement;
(b) Does not contravene any permit term or condition for monitoring, testing, recordkeeping or reporting, or any compliance certification requirement;

(c) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapter 62-212 or 62-296, F.A.C.;

(d) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject including any federally enforceable emissions cap or federally enforceable alternative emissions limit.

(2) A Title V source may immediately implement such changes after they have been incorporated into the terms and conditions of a new or revised construction permit issued pursuant to Chapter 62-212, F.A.C., and after the source provides to EPA, the Department, each affected state and any approved local air program having geographic jurisdiction over the source, a copy of the source's application for operation permit revision. The Title V source may conform its application for construction permit to include all information required by Rule 62-213.420, F.A.C., in lieu of submitting separate application forms.

(3) The Department shall process the application for operation permit revision in accordance with the provisions of Chapter 62-213, F.A.C., except that the Department shall issue a draft permit revision or a determination to deny the revision within 60 days of receipt of a complete application for operation permit revision or, if the Title V source has submitted a construction permit application conforming to the requirements of Rule 62-213.420, F.A.C., the Department shall issue a draft permit or a determination to deny the revision at the same time the Department issues its determination on issuance or denial of the construction permit application. The Department shall not take final action until all the requirements of Rule 62-213.430(1)(a), (c), (d), and (e), F.A.C., have been complied with.

(4) Pending final action on the operation permit revision application, the source shall implement the changes in accordance with the terms and conditions of the source's new or revised construction permit.

(5) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes until after the Department takes final action to issue the operation permit revision.

(6) If the Department denies the source's application for operation permit revision, the source shall cease implementation of the proposed changes.

[Rule 62-213.412, F.A.C.]

34. Permit Applications.

(1) Duty to Apply. For each Title V source, the owner or operator shall submit a timely and complete permit application in compliance with the requirements of Rules 62-213.420, 62-4.050(1) & (2), and 62-210.900, F.A.C.

(a) Timely Application.

3. For purposes of permit renewal, a timely application is one that is submitted in accordance with Rule 62-4.090, F.A.C.

(b) Complete Application.

1. Any applicant for a Title V permit, permit revision or permit renewal must submit an application on DEP Form No. 62-210.900(1), which must include all the information specified by Rule 62-213.420(3), F.A.C., except that an application for permit revision must contain only that information related to the proposed change. The applicant shall include information concerning fugitive emissions and stack emissions in the application. Each application for permit, permit revision or permit renewal shall be certified by a responsible official in accordance with Rule 62-213.420(4), F.A.C.

2. For those applicants submitting initial permit applications pursuant to Rule 62-213.420(1)(a)1., F.A.C., a complete application shall be an application that substantially addresses all the information required by the application form number 62-210.900(1), and such applications shall be deemed complete within sixty days of receipt of a signed and certified application unless the Department notifies the applicant of incompleteness within that time. For all other applicants, the applications shall be deemed complete sixty days after receipt, unless the Department, within sixty days after receipt of a signed application for permit, permit revision or permit renewal, requests additional documentation or information needed to process the application. An applicant making timely and complete application for permit, or timely application for permit renewal as described by Rule 62-4.090(1), F.A.C., shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, provided the applicant complies with all the provisions of Rules 62-213.420(1)(b)3. and 4. F.A.C. Failure of the Department to request additional information within sixty days of receipt of a properly signed application shall not impair the Department's ability to request additional information pursuant to Rules 62-213.420(1)(b)3. and 4., F.A.C.

3. For those permit applications submitted pursuant to the provisions of Rule 62-213.420(1)(a)1., F.A.C., the Department shall notify the applicant if the Department becomes aware at any time during processing of the application that the application contains incorrect or incomplete information. The applicant shall submit the corrected or supplementary information to the Department within ninety days unless the applicant has requested and been granted additional time to submit the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days or such additional time as requested and granted shall render the application incomplete.
4. For all applications other than those addressed at Rule 62-213.420(1)(b)3., F.A.C., should the Department become aware, during processing of any application that the application contains incorrect information, or should the Department become aware, as a result of comment from an affected State, an approved local air program, EPA, or the public that additional information is needed to evaluate the application, the Department shall notify the applicant within 30 days. When an applicant becomes aware that an application contains incorrect or incomplete information, the applicant shall submit the corrected or supplementary information to the Department. If the Department notifies an applicant that corrected or supplementary information is necessary to process the permit, and requests a response, the applicant shall provide the information to the Department within ninety days of the Department request unless the applicant has requested and been granted additional time to submit the information or, the applicant shall, within ninety days, submit a written request that the Department process the application without the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days, or such additional time as requested and granted, or to demand in writing within ninety days that the application be processed without the information shall render the application incomplete. Nothing in this section shall limit any other remedies available to the Department.

[Rules 62-213.420(1)(a)3. and 62-213.420(1)(b)1., 2., 3. & 4., F.A.C.]

35. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. (also, see Condition No. 50.)
[Rule 62-213.420(2), F.A.C.]

36. Standard Application Form and Required Information. Applications shall be submitted under Chapter 62-213, F.A.C., on forms provided by the Department and adopted by reference in Rule 62-210.900(1), F.A.C. The information as described in Rule 62-210.900(1), F.A.C., shall be included for the Title V source and each emissions unit. An application must include information sufficient to determine all applicable requirements for the Title V source and each emissions unit and to evaluate a fee amount pursuant to Rule 62-213.205, F.A.C.
[Rule 62-213.420(3), F.A.C.]

37. 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.
[Rule 62-213.420(4), F.A.C.]

38. a. Permit Renewal and Expiration. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) and 62-213.420(3), F.A.C. Unless a Title V source submits a timely application for permit renewal in accordance with the requirements of Rule 62-4.090(1), F.A.C., the existing permit shall expire and the source's right to operate shall terminate.

b. Permit Revision Procedures. Permit revisions shall meet all requirements of Chapter 62-213, F.A.C., including those for content of applications, public participation, review by approved local programs and affected states, and review by EPA, as they apply to permit issuance and renewal, except that permit revisions for those activities implemented pursuant to Rule 62-213.412, F.A.C., need not meet the requirements of Rule 62-213.430(1)(b), F.A.C. The Department shall require permit revision in accordance with the provisions of Rule 62-4.080, F.A.C., and 40 CFR 70.7(f), whenever any source becomes subject to any condition listed at 40 CFR 70.7(f)(1), hereby adopted and incorporated by reference. The below requirements from 40 CFR 70.7(f) are adopted and incorporated by reference in Rule 62-213.430(4), F.A.C.:

o 40 CFR 70.7(f): Reopening for Cause. (also, see Condition No. 4)

(1) This section contains provisions from 40 CFR 70.7(f) that specify the conditions under which a Title V permit shall be reopened prior to the expiration of the permit. A Title V permit shall be reopened and revised under any of the following circumstances:

(i) Additional applicable requirements under the Act become applicable to a major Part 70 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 40 CFR 70.4(b)(10)(i) or (ii).

(ii) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approved by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit.

(iii) The permitting authority or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

(iv) The Administrator or the permitting authority determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(2) Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

(3) Reopenings under 40 CFR 70.7(f)(1) shall not be initiated before a notice of such intent is provided to the Part 70 source by the permitting authority at least 30 days in advance of the date that the permit is to be reopened, except that the permitting authority may provide a shorter time period in the case of an emergency.

[Rules 62-213.430(3) & (4), F.A.C.; and, 40 CFR 70.7(f)]

39. Insignificant Emissions Units or Pollutant-Emitting Activities.

(a) All requests for determination of insignificant emissions units or activities made pursuant to Rule 62-213.420(3)(m), F.A.C., shall be processed in conjunction with the permit, permit renewal or permit revision application submitted pursuant to Chapter 62-213, F.A.C. Insignificant emissions units or activities shall be approved by the Department consistent with the provisions of Rule 62-4.040(1)(b), F.A.C. Emissions units or activities which are added to a Title V source after issuance of a permit under Chapter 62-213, F.A.C., 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 as insignificant pursuant to Rule 62-213.430(6), F.A.C.

(b) An emissions unit or activity shall be considered insignificant if:

1. Such unit or activity would be subject to no unit-specific applicable requirement;
2. Such unit or activity, in combination with other units or activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined in Rule 62-213.420(3)(c)1., F.A.C., unless it is acknowledged in the permit application that such units or activities would cause the facility to exceed such threshold(s); and
3. Such unit or activity would not emit or have the potential to emit:
   a. 500 pounds per year or more of lead and lead compounds expressed as lead;
   b. 1,000 pounds per year or more of any hazardous air pollutant;
   c. 2,500 pounds per year or more of total hazardous air pollutants; or
   d. 5.0 tons per year or more of any other regulated pollutant.

[Rule 62-213.430(6), F.A.C.]

40. Permit Duration. Operation permits for Title V sources may not be extended as provided in Rule 62-4.080(3), F.A.C., if such extension will result in a permit term greater than five (5) years.

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

41. Monitoring Information. All records of monitoring information shall specify the date, place, and time of sampling or measurement and the operating conditions at the time of sampling or measurement, the date(s) analyses were performed, the company or entity that performed the analyses, the analytical techniques or methods used, and the results of such analyses.
[Rule 62-213.440(1)(b)2.a., F.A.C.]

42. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
[Rule 62-213.440(1)(b)2.b., F.A.C.]

43. Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports.
[Rule 62-213.440(1)(b)3.a., F.A.C.]

44. Deviation from Permit Requirements Reports. The permittee shall report in accordance with the requirements of Rules 62-210.700(6) and 62-4.130, F.A.C., any deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken.
[Rule 62-213.440(1)(b)3.b., F.A.C.]

45. Reports. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C.
[Rule 62-213.440(1)(b)3.c, F.A.C.]

46. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect.
[Rule 62-213.440(1)(d)1., F.A.C.]

47. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity.
[Rule 62-213.440(1)(d)3., F.A.C.]

48. A Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C.
[Rule 62-213.440(1)(d)4., F.A.C.]

49. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference.
[Rule 62-213.440(1)(d)5., F.A.C.]

50. Confidentiality Claims. Any permittee may claim confidentiality of any data or other information by complying with Rule 62-213.420(2), F.A.C. (also, see Condition No. 35.)
[Rule 62-213.440(1)(d)6., F.A.C.]

51. Statement of Compliance. The permittee shall submit a statement of compliance with all terms and conditions of the permit. Such statements shall be submitted to the Department and EPA annually, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement. Such statements shall be accompanied by a certification in accordance with Rule 62-213.420(4), F.A.C. The statement of compliance shall include all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C.

o 40 CFR 70.6(c)(5)(iii). The compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(A) The identification of each term or condition of the permit that is the basis of the certification;

(B) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required under 40 CFR 70.6(a)(3). If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information;

(C) The status of compliance with the terms and conditions of the permit for the period covered by the certification, based on the method or means designated in paragraph (c)(5)(iii)(B) of this section. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under part 64 of this chapter occurred; and

(D) Such other facts as the permitting authority may require to determine the compliance status of the source.

The statement shall be accompanied by a certification by a responsible official, in accordance with Rule 62-213.420(4), F.A.C. The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rule 62-213.440(3), F.A.C.]

52. Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall be deemed compliance with any applicable requirements in effect as of the date of permit issuance, provided that the source included such applicable requirements in the permit application. Nothing in Rule 62-213.460, F.A.C., or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program.

{Permitting note: The permit shield is not in effect until the effective date of the permit.}

[Rule 62-213.460, F.A.C.]

53. Forms and Instructions. The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The form is listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, or by contacting the appropriate permitting authority.

(1) Major Air Pollution Source Annual Emissions Fee (AEF) Form.

[Rule 62-213.900(1), F.A.C.]

Chapter 62-256, F.A.C.

54. Not federally enforceable. Open Burning. This permit does not authorize any open burning nor does it constitute any waiver of the requirements of Chapter 62-256, F.A.C. Source shall comply with Chapter 62-256, F.A.C., for any open burning at the source.

[Chapter 62-256, F.A.C.]

Chapter 62-281, F.A.C.

55. Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Rule 62-281.100, F.A.C. Those requirements include the following restrictions:

(1) Any facility having any refrigeration equipment normally containing 50 (fifty) pounds of refrigerant, or more, must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added pursuant to 40 CFR 82.166;

(2) No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided at 40 CFR 82.34 and 40 CFR 82.40, and properly uses equipment approved pursuant to 40 CFR 82.36 and 40 CFR 82.38, and complies with 40 CFR 82.42;
(3) No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or Class II substance at 40 CFR 82, Subpart A, Appendices A and B, except in compliance with Rule 62-281.100, F.A.C., and 40 CFR 82.34(b), 40 CFR 82.42, and/or 40 CFR 82.166;
(4) No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or Class II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined at 40 CFR 82.152) for service, maintenance or repair unless the person has been properly trained and certified pursuant to 40 CFR 82.161 and unless the person uses equipment certified for that type of appliance pursuant to 40 CFR 82.158 and unless the person observes the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;
(5) No person may dispose of appliances (except small appliances, as defined at 40 CFR 82.152) without using equipment certified for that type of appliance pursuant to 40 CFR 82.158 and without observing the practices set forth at 40 CFR 82.156 and 40 CFR 82.166;
(6) No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined at 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82, Subpart F.
[40 CFR 82; and, Chapter 62-281, F.A.C. (Chapter 62-281, F.A.C., is not federally enforceable)]

Chapter 62-296, F.A.C.

56. Industrial, Commercial, and Municipal Open Burning Prohibited. Open burning in connection with industrial, commercial, or municipal operations is prohibited, except when:

(a) Open burning is determined by the Department to be the only feasible method of operation and is authorized by an air permit issued pursuant to Chapter 62-210 or 62-213, F.A.C.; or

(b) An emergency exists which requires immediate action to protect human health and safety; or

(c) A county or municipality would use a portable air curtain incinerator to burn yard trash generated by a hurricane, tornado, fire or other disaster and the air curtain incinerator would otherwise be operated in accordance with the permitting exemption criteria of Rule 62-210.300(3), F.A.C.

[Rule 62-296.320(3), F.A.C.]

57. Unconfined Emissions of Particulate Matter.
(4)(c)1. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any emissions unit whatsoever, including, but not limited to, vehicular movement, transportation of materials, construction, alteration, demolition or wrecking, or industrially related activities such as loading, unloading, storing or handling, without taking reasonable precautions to prevent such emission.

3. Reasonable precautions may include, but shall not be limited to the following:

a. Paving and maintenance of roads, parking areas and yards.

b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.

c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar emissions units.

d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the emissions unit to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.

e. Landscaping or planting of vegetation.

f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.

g. Confining abrasive blasting where possible.

h. Enclosure or covering of conveyor systems.

4. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice.
[Rules 62-296.320(4)(c)1., 3., & 4. F.A.C.]

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APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)

Stack Sampling Facilities Provided by the Owner of an Emissions Unit. This section describes the minimum requirements for stack sampling facilities that are necessary to sample point emissions units. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. Emissions units must provide these facilities at their expense. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.
2. The ports shall be capable of being sealed when not in use.
3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) Access to Work Platform.

1. Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f) Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g) Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

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

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE (version dated 7/96)

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period [1]: _____

Emission data summary [1]	CMS performance summary [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown ..... ____	a. Monitor equipment malfunctions ..... ____
b. Control equipment problems ..... ____	b. Non-Monitor equipment malfunctions ..... ____
c. Process problems ..... ____	c. Quality assurance calibration ..... ____
d. Other known causes ..... ____	d. Other known causes ..... ____
e. Unknown causes ..... ____	e. Unknown causes ..... ____
2. Total duration of excess emissions ..... ____	2. Total CMS Downtime ..... ____
3. Total duration of excess emissions x (100) / [Total source operating time] ..... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] ..... ____ % [2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: On a separate page, describe any changes since last quarter in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ *Date*: _____

Title: _____

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

PSD-FL-212

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

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

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	-
Be			0.00011	0.00011	0.0004
Hg			0.0009	0.0009	0.1
Pb			0.05746	0.05746	0.6
As			0.004854	0.004854	Any

* With power augmentation

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

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 potentially 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 $1,455,987.33, the incremental cost effectiveness ($/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 <u>not</u> 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 1.25% 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:

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

March 29, 1995
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

April 11th, 1995
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	
	)	
Florida Electric Power Coordinating Group, Inc.,	)	ASP No. 97-B-01
	)	
Petitioner.	)	

ORDER ON REQUEST FOR ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), the Florida Electric Coordinating Group, Incorporated, (FCG) petitioned for approval to: (1) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test; and, (2) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test during the year prior to renewal of an operation permit. This Order is intended to clarify particulate testing requirements for those fossil fuel steam generators which primarily burn gaseous fuels including, but not necessarily limited to natural gas.

Having considered the provisions of Rule 62-296.405(1), F.A.C., Rule 62-297.310(7), F.A.C., and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS OF FACT

1. The Florida Electric Power Coordinating Group, Incorporated, petitioned the Department to exempt those fossil fuel steam generators which have a heat input of more than 250 million Btu per hour and burn solid and/or liquid fuel less than 400 hours during the year from the requirement to conduct an annual particulate matter compliance test. [Exhibit 1]

2. Rule 62-296.405(1)(a), F.A.C., applies to those fossil fuel steam generators that are not subject to the federal standards of performance for new stationary sources (NSPS) in 40 CFR 60 and which have a heat input of more than 250 million Btu per hour.

3. Rule 62-296.405(1)(a), F.A.C., limits visible emissions from affected fossil fuel steam generators to, "20 percent opacity except for either one six-minute period per hour during which

not exceed 40 percent. The option selected shall be specified in the emissions unit's construction and operation permits. Emissions units governed by this visible emission limit shall test for particulate emission compliance annually and as otherwise required by Rule 62-297, F.A.C."

4. Rule 62-296.405(1)(a), F.A.C., further states, "Emissions units electing to test for particulate matter emission compliance quarterly shall be allowed visible emissions of 40 percent opacity. The results of such tests shall be submitted to the Department. Upon demonstration that the particulate standard has been regularly complied with, the Secretary, upon petition by the applicant, shall reduce the frequency of particulate testing to no less than once annually.

5. Rule 297.310(7)(a)1., F.A.C., states, "The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit."

6. Rule 297.310(7)(a)3., F.A.C., states, "The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision.

7. Rule 297.310(7)(a)3., F.A.C., further states, "In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal: a. Did not operate; or, b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours."

8. Rule 297.310(7)(a)4., F.A.C., states, "During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for: a. Visible emissions, if there is an applicable standard; b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant...."

9. Rule 297.310(7)(a)5., F.A.C., states, "An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours."

10. Rule 297.310(7)(a)6., F.A.C., states, "For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be

required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup."

11. Rule 297.310(7)(a)7., F.A.C., states, "For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup." [Note: The reference should be to Rule 62-296.405(1)(a), F.A.C., rather than Rule 62-296.405(2)(a), F.A.C.]

12. The fifth edition of the U. S. Environmental Protection Agency's Compilation of Air Pollutant Emission Factors, AP-42, that emissions of filterable particulate from gas-fired fossil fuel steam generators with a heat input of more than about 10 million Btu per hour may be expected to range from 0.001 to 0.006 pound per million Btu. [Exhibit 2]

13. Rule 62-296.405(1)(b), F.A.C. and the federal standards of performance for new stationary sources in 40 CFR 60.42, Subpart D, limit particulate emissions from uncontrolled fossil fuel fired steam generators with a heat input of more than 250 million Btu to 0.1 pound per million Btu.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider the matter pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Pursuant to Rule 62-297.310(7), F.A.C., the Department may require Petitioner to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

3. There is reason to believe that a fossil fuel steam generator which does not burn liquid and/or solid fuel (other than during startup) for a total of more than 400 hours in a federal fiscal year and complies with all other applicable limits and permit conditions is in compliance with the applicable particulate mass emission limiting standard.

ORDER

Having considered the requirements of Rule 62-296.405, F.A.C., Rule 62-297.310, F.A.C., and supporting documentation, it is hereby ordered that:

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

2. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup;

3. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(1)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup;

4. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

5. Pursuant to Rule 62-297.310(7), F.A.C., owners of affected fossil fuel steam generators may be required to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

6. Pursuant to Rule 62-297.310(8), F.A.C., owners of affected fossil fuel steam generators shall submit the compliance test report to the District Director of the Department district office having jurisdiction over the emissions unit and, where applicable, the Air Program Administrator of the appropriate Department-approved local air program within 45 days of completion of the test.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 of the Florida Statutes, or a party requests mediation as an alternative remedy under section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of

the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department File Number, and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by each petitioner, if any;

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement identifying the rules or statutes each petitioner contends require reversal or modification of the Department's action or proposed action; and,

(g) A statement of the relief sought by each petitioner, stating precisely the action each petitioner wants the Department to take with respect to the Department's action or proposed action in the notice of intent.

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

A person whose substantial interests are affected by the Department's proposed decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information:

(a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any;

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

(d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following:

(a) The names, addresses, and telephone numbers of any persons who may attend the mediation;

(b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

(c) The agreed allocation of the costs and fees associated with the mediation;

(d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

(e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

(f) The name of each party's representative who shall have authority to settle or recommend settlement; and

(g) The signatures of all parties or their authorized representatives.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will

specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver, when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully

each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

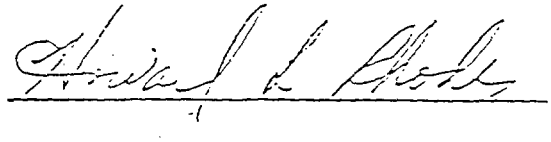
This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 17 day of March, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 18th day of March 1997.

Clerk Stamp

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

Martha Ollinger 3-18-97
Clerk Date

IDA ELECTRIC POWER COORDINATING GROUP, INC. (FCG)
30 STREET, SUITE 100 • (813) 289-5644 • FAX (813) 289-5648
A, FLORIDA 33609-1004

January 28, 1997

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32301

RECEIVED
JAN 28 1997
BUREAU OF
AIR REGULATION

RE: Comments Regarding Draft Title V Permits

Dear Mr. Fancy:

The Florida Electric Power Coordinating Group, Inc. (FCG), which is made up of 36 utilities owned by investors, municipalities, and cooperatives, has been following the implementation of Title V in Florida and recently submitted comments to you on draft Title V permit conditions by letter dated December 4, 1996. As indicated in that letter, representatives from the FCG would like to meet with you and other members of your air permitting staff to discuss some significant concerns that FCG member companies have regarding conditions that may be included in Title V permits issued by your office. While we will be discussing these issues with you and your staff in greater detail at that meeting, we would like to explain some of our concerns in this letter.

Primarily, the FCG members are concerned that the Title V permits may contain conditions that are much different in important respects than those conditions currently included in existing air permits. During the rulemaking workshops and seminars conducted by the Department to discuss the rules implementing the Title V permitting program, representations were made on several occasions that industry could expect to see permit conditions that were substantively similar to existing permit conditions and that primarily the format was changing. Representations were also made to industry that Title V did not impose additional substantive requirements beyond what was already required under the Department's rules. Based on the first draft Title V permit that we have reviewed, we are concerned that there may be some attempt to change the substantive requirements on existing facilities through the Title V permitting process, and we would like to discuss this with you at the meeting we have scheduled for January 30, 1997.

1. Federal Enforceability--The FCG has long been concerned about the designation of non-federally enforceable permit terms and conditions. We are concerned about this issue because the Department's first draft Title V permits have included language stating that *all* terms and conditions would become federally enforceable once the permit is issued. This approach is consistant with the Department's guidance memorandum dated September 13, 1996 (DAPM-PER/V-18), but we understand that the Department may now intend to remove all references to

the federal enforceability of permit terms and conditions. We are also concerned about this approach because a Title V permit is generally federally enforceable and, without any designation of non-federally enforceable terms and conditions, the entire permit could be interpreted to be federally enforceable. As we stated in the December 4 letter as well as our letter dated October 11, 1996, all terms and conditions in a Title V permit do *not* become enforceable by the U.S. Environmental Protection Agency and citizens under the Clean Air Act simply by inclusion in a Title V permit. To make it clear which provisions in a Title V permit are not federally enforceable (which are being included because of state or local requirements only), it is very important to specifically designate those conditions as having no federally enforceable basis. Such a designation is actually required under the federal Title V rules, which provide that permitting agencies are to "specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements." 40 CFR § 70.6(b). We would like to discuss with you our concerns about this issue and to again specifically request that when Title V permits are issued by the Department, conditions having no federally enforceable basis clearly be identified as such.

2. PM Testing on Gas--The FCG understands that the Department may attempt to require annual particulate matter compliance testing while firing natural gas to determine compliance with the 0.1 lb/mmBtu emission limit established under Rule 62-296.405(1)(b), F.A.C. The FCG member companies feel strongly that compliance testing for particulate matter should not be required while firing natural gas. The Department has not historically required particulate matter compliance testing while firing natural gas, it is not required under the current permits for these units, and it should not be necessary since natural gas is such a clean fuel. Typically only *de minimis* amounts of particulate matter would be expected from the firing of natural gas, so compliance testing would not provide meaningful information to the Department, and the expense to conduct such tests is not justified. We understand that Department representatives suggested that industry could pursue an alternative test procedure under Rule 62-297.620, F.A.C., to allow a visible emissions test to be used in lieu of a stack test for determining compliance with the particulate matter limit. While certainly a visible emissions test would be preferable over a stack test, neither of these tests should be needed to demonstrate compliance with the particulate matter limit of 0.1 lb/mmBtu while burning natural gas. The FCG strongly urges that the Department reconsider its position on this issue and clarify that compliance testing for particulate matter while firing natural gas is not required.

3. Excess Emissions--By letter dated December 5, 1996, the U.S. Environmental Protection Agency (EPA) submitted a letter commenting on a draft Title V permit that had been issued by the Department and indicated some concern regarding excess emission provisions included in conditions that were quoted from Rule 62-210.700, F.A.C. Because the permit conditions cited simply quote the applicable provisions of the Department's rules regarding

excess emissions and because these rules have been approved as part of Florida's State Implementation Plan, the permit conditions are appropriate to be included in the permit. We understand that the Department intends to include as applicable requirements in Title V permit conditions the provisions of Rule 62-210.700, F.A.C. If the Department receives any further adverse comments regarding the excess emissions rule under 62-210.700, F.A.C., we would appreciate your contacting us. Because this issue is so important to us, we would like to discuss it with you in greater detail at our meeting on January 30.

4. Compliance Testing for Combustion Turbines--While the Department's November 22, 1995, guidance regarding the compliance testing requirements for combustion turbines clearly states that the use of heat input curves based on ambient temperatures and humidities is to be included as a permit condition *only* if requested by a permittee, we understand that the Department may intend to include this requirement in Title V permits for all combustion turbines. As we are sure you recall, the FCG worked over a period of several months with the Department on the development of the guidance memorandum and it was clearly understood by FCG members that the heat input curves would not be mandated but would remain voluntary for any existing combustion turbine. It was also understood by FCG members that the requirement to conduct testing at 95 to 100 percent of capacity would be required only if the permit applicant requested the use of heat input curves. We understand that the Department may be interpreting the requirement to use heat input curves and to test at 95 to 100 percent of permitted capacity to be mandatory for all combustion turbines. We would like to clarify this with you during our meeting. Also, we would like to confirm that, regardless of whether a combustion turbine uses heat input curves or tests at 95 to 100 percent of permitted capacity, it is necessary to test at four load points and correct to ISO *only* to determine compliance with the nitrogen oxides (NOx) standard under New Source Performance Standard Subpart GG under 40 CFR § 60.332 and not annually thereafter.

5. Test Methods--The FCG is concerned about the possibility of the Department requiring a full permit revision to authorize the use of an approved test method not specifically identified in a Title V permit, even though the Department may have separately approved the use of the particular test method for a unit (i.e., through a compliance test protocol). It is the FCG's position that language should be included in all Title V permits indicating that other test methods approved by the Department may be used. Further, a full permit revision (including public notice) should *not* be necessary when a test method not previously identified in the permit is approved for use by a unit. The Department's subsequent approval of test methods should simply be included in the next permit renewal cycle. The FCG understands that the Department planned to confirm this approach with the U.S. Environmental Protection Agency Region IV, and we would like to discuss this issue with you at the January 30 meeting to learn of the agency's response.

6. Quarterly Reports--The FCG understands that the Department may be interpreting the quarterly reporting requirements under Rule 62-296.405(1)(g), F.A.C., to apply regardless of whether continuous emissions monitors were required under the preceding Rule 62-296.405(1)(f), F.A.C. It is the FCG's position that quarterly reports are required under Rule 62-296.405(1)(g) only when continuous emissions monitors are required under the preceding paragraph (f). While this may not be entirely clear from the language of the rules, paragraphs (f) and (g) were originally included in a separate rule on "continuous emission monitoring requirements" where it was very clear that the requirements of paragraph (g) applied *only* if continuous emission monitoring was required under paragraph (f). Research indicates that Rule 17-2.710, F.A.C. (copy attached), where these provisions were originally located, was first transferred to Rule 17-297.500, F.A.C. (which later became Rule 62-297.500), later repealed in November of 1994, and ultimately replaced with what is now Rule 62-296.405(1)(f) and (g), F.A.C. To the extent that an emissions unit is not subject to Rule 62-296.405(1)(f) and is not required to install and operate continuous emissions monitors (e.g., oil- and gas-fired units), the quarterly reporting requirements of paragraph (g) should not apply.

7. Trivial Activities--As you may recall, in May of 1996, the FCG submitted to the Department a list of small, *de minimis* emissions units and activities that it considered to be "trivial," consistent with the list developed by EPA as part of the Title V "White Paper" and incorporated by reference by the Department in its March 15, 1996, guidance memorandum (DARM-PER/V-15-Revised). We never received a response from the Department and now understand that the Department may not have made a determination as to whether any of the emission units or activities on the list should qualify as "trivial." This is an important issue to the FCG because only "trivial" activities can be omitted from the Title V permit application and permit, and ultimately omitted from emission estimates in the annual air operation reports under Rule 62-210.370(3), F.A.C. The FCG remains hopeful that the Department will consider its request to determine that most, if not all, of the emission units and activities on the May, 1996, list to be "trivial." We would like to discuss a possible resolution of this issue with you and your staff at the January 30 meeting.

8. Permit Shield--The FCG continues to be concerned about the language in Conditions 5 and 20 of Appendix TV-1, Title V Conditions, which circumvents the permit shield provisions under Section 403.0872(15), Florida Statutes, and Rule 62-213.460, F.A.C. The FCG believes that these conditions should be deleted in their entirety. To the extent that the Department attempt to caveat the applicability of those conditions, the FCG believes that it is important to cite to not only the regulatory citation for the permit shield but the statutory citation as well.

Thank you again for considering the FCG's comments on the draft Title V permits. We very much appreciate the cooperation we have received from the Department throughout the

Title V implementation process, and we look forward to our meeting later this week. If you have any questions in the meantime, please call me at 561-625-7661.

Sincerely,

Rich Piper

Rich Piper, Chair
FCG Air Subcommittee

Enclosures

cc: Howard L. Rhodes, DEP
John Brown, DEP
Pat Comer, DEP OGC
Scott M. Sheplak, DEP
Edward Svec, DEP
FCG Air Subcommittee
Angela Morrison, HGSS

sssct

AP-42
FIFTH EDITION
JANUARY 1995

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

Office Of Air Quality Planning And Standards
Office Of Air And Radiation
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

January 1995

Exhibit 3

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Section 5.3, Natural Gas Processing). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9000 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions And Controls[3-5]

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e.g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas

recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensable fractions, based on the EPA sampling method. Filterable and condensable emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensable material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, and 1.4-3.[6] For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

Table 1.4-1 (Metric And English Units). EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	Filterable PM[c]			Condensable PM[d]		
	$kg/10^6 m^3$	$lb/10^6 ft^3$	RATING	$kg/10^6 m^3$	$lb/10^6 ft^3$	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	16 - 80	1 - 5	B	ND	ND	NA
Small industrial boilers (10 - 100) (1-02-006-02)	99	6.2	B	120	7.5	D
Commercial boilers (0.3 - < 10) (1-03-006-03)	72	4.5	C	120	7.5	C
Residential furnaces (< 0.3) (No SCC)	2.8	0.18	C	180	11	D

[a] References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

[b] SCC = Source Classification Code.

[c] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Condensable PM is that particulate matter collected using EPA Method 202, (or equivalent). Total PM is the sum of the filterable PM and condensable PM. All PM emissions can be assumed to be less than 10 micrometers in aerodynamic equivalent diameter (PM-10).

Table 1.4-2 (Metric And English Units). EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	SO_2[c]			NO_x[d]			CO[e]		
	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING
Utility/large Industrial Boilers (>100) (1-01-006-01, 1-01-006-04)									
Uncontrolled	9.6	0.6	A	8800	550[f]	A	640	40	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	ND	ND	NA
Controlled - Flue gas recirculation	9.6	0.6	A	850	53[f]	D	ND	ND	NA
Small Industrial Boilers (10 - 100) (1-02-006-02)									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3 - <10) (1-03-006-03)									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO_x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	ND	ND	NA
Residential Furnaces (<0.3) (No SCC)									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

[a] Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

[b] SCC = Source Classification Code.

[c] Reference 7. Based on average sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).

Table 1.4-2 (cont.).

[d] References 10,15-19. Expressed as NO_2. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO_x emissions from controlled boilers will be reduced at low load conditions.

[e] References 9-10,16-18,20-21.

[f] Emission factors apply to packaged boilers only.

(English Units). EMISSION FACTORS FOR CARBON DIOXIDE (CO_2) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	CO_2[c]			TOC[d]		
	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	ND[e]	ND	NA	28[f]	1.7[f]	C
Small industrial boilers (10 - 100) (1-02-006-02)	1.9 E+06	1.2 E+05	D	92[g]	5.8[g]	C
Commercial boilers (0.3 - < 10) (1-03-006-03)	1.9 E+06	1.2 E+05	C	128[h]	8.0[h]	C
Residential furnaces (No SCC)	2.0 E+06	1.3 E+05	D	180[h]	11[h]	D

[a] All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lb of pollutant/10^6 cubic feet. Based on an averagd natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given factor by the ratio of the specified heating value to this average heating value. NA = not applicable.

[b] SCC = Source Classification Code.

[c] References 10,22-23.

[d] References 9-10,18.

[e] ND = no data.

[f] Reference 8: methane comprises 17% of organic compounds.

[g] Reference 8: methane comprises 52% of organic compounds.

[h] Reference 8: methane comprises 34% of organic compounds.

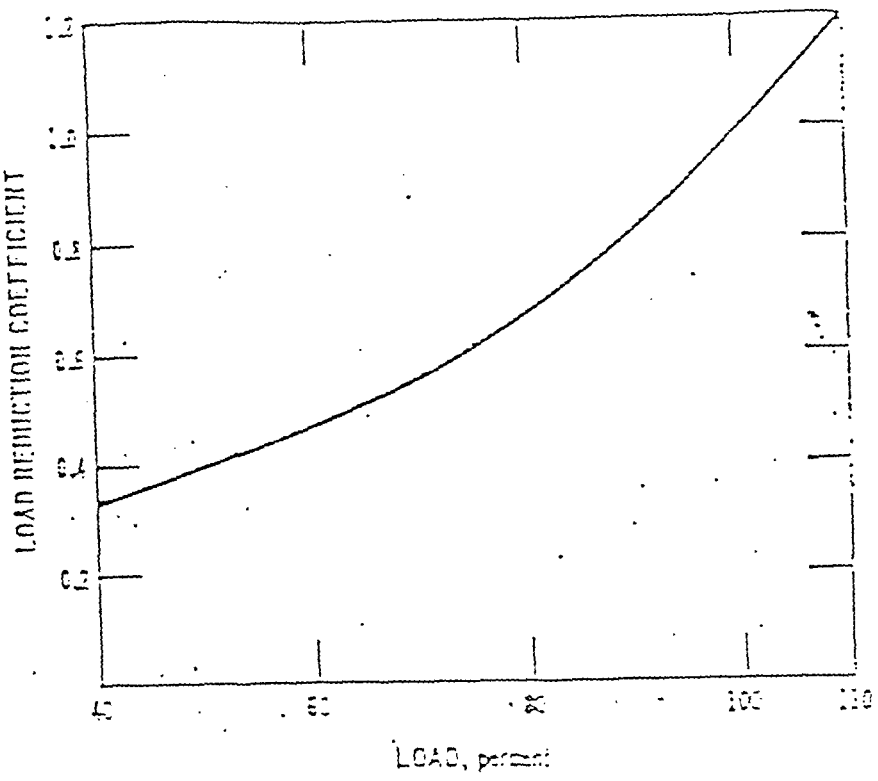


Figure 1.4-1. Load reduction coefficient as a function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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

16. *Results From Performance Tests: California Milk Producers Boiler No. 5*, Energy Systems Associates, Tustin, CA, November 1984.

17. *Source Test For Measurement of Nitrogen Oxides and Carbon Monoxide Emissions From Boiler Exhaust at GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.

18. J. F. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

19. *NO_x Emission Control Technology Update*, EPA Contract No. 68-01-6553, Radian Corporation, Research Triangle Park, NC, January 1984.

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21. *Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503*, American Gas Association Laboratories, Cleveland, OH, May 1973.

22. *Thirty-day Field Test of Industrial Boilers: Site 5 - Gas-fired Low-NO_x Burner*, EPA-600/7-81-095a, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

23. Private communication from Kim Black (Industrial Combustion) to Ralph Harris (MSI), Independent Third Party Source Tests, February 7, 1992.

Department of
Environmental Protection

on Chiles
overnor

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

Virginia B. Wetherell
Secretary

July 9, 1997

Certified Mail - Return Receipt Requested

Mr. Rich Piper, Chair
Florida Power Coordinating Group, Inc.
405, Reo Street, Suite 100
Tampa, Florida 33609-1004

Dear Mr. Piper:

Enclosed is a copy of a Scrivener's Order correcting an error in the Order concerning particulate matter testing of natural gas fired boilers.

If you have any questions concerning the above, please call Yogesh Manocha at 904/488-6140, or write to me.

Sincerely,

M. D. Harley, P.E., DEE
P.E. Administrator
Emissions Monitoring Section
Bureau of Air Monitoring and
Mobile Sources

MDH:ym

cc: Dotty Diltz, FDEP
Pat Comer, FDEP

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	
	)	
Florida Electric Power Coordinating Group, Inc.,	)	ASP No. 97-B-01
	)	
Petitioner.	)	

ORDER CORRECTING SCRIVENER'S ERROR

The Order which authorizes owners of natural gas fired fossil fuel steam generators to forgo particulate matter compliance testing on an annual basis and prior to renewal of an operation permit entered on the 17th day of March, 1997, is hereby corrected on page 4, paragraph number 4, by deleting the words "pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.":

4. In renewing an air operation permit ~~pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.,~~ the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

DONE AND ORDERED this 2 day of July, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 10TH day of July 1997.

Clerk Stamp

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

Martha Dwellie 7/10/97
Clerk Date

Phase II Permit Application

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

This submission is: [X] New [ ] Revised

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

Plant Name	State	ORIS Code
Deerhaven	FL	663

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

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
B1	Yes	NO		
B2	Yes	NO		
CT3	Yes	NO	12/20/95	Unknown
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

Plant Name (from Step 1)

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

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

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

Name John F. Hancock, Designated Representative	
Signature	Date 12/22/95

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

AIRS
FINDS

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Expires 12-31-96

EPA

Phase I Permit Application
NOx Compliance Plan

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

This submission is: [X] New [ ] Revised

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

Plant Name	State	ORIS Code
DEERHAVEN GENERATING STATION	FL	663

STEP 2

Identify each affected group 1 boiler using the boiler ID# from NADB. Indicate the type of boiler; enter "T" for tangentially fired boilers and "DBW" for dry bottom wall-fired boilers. Indicate the compliance options selected for each unit.

	ID# B2 / Type DBW	ID# / Type	ID# / Type	ID# / Type	ID# / Type	ID# / Type
Standard annual average emission limitation of 0.45 lb/mmBtu *(for tangentially fired boilers)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Standard annual average emission limitation of 0.50 lb/mmBtu *(for dry bottom wall-fired boilers)*	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) *(check the standard emission limitation box above for the most stringent limitation applicable to any unit utilizing the stack)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Early Election *(enter the year, not later than 1997, and check one of the standard emission limitation boxes)*	1997					
Alternative Emissions Limitation *(include Alternative Emissions Limitation Demonstration Period form)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
NOx Averaging Plan *(include NOx Averaging form)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) electing NOx Averaging *(check the NOx Averaging Plan box and include NOx Averaging form)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
NOx Compliance Extension Plan *(include NOx Compliance Extension form)*	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(a)(1)(i)). If this source is affected for sulfur dioxide during Phase I, these requirements are also listed in this source's Acid Rain Permit on the permit application forms.

Special Provisions for Early Election Units

Emissions Limitations

Sulfur Dioxide. Notwithstanding 40 CFR 72.9, a unit that is governed by an approved early election plan and that is not a substitution unit under 40 CFR 72.41 or a compensating unit under 40 CFR 72.43 shall not be subject to the following standard requirements under 40 CFR 72.9 for Phase I:

(i) The permit requirements under 40 CFR 72.9(a)(1)(i) and
(ii) The sulfur dioxide requirements under 40 CFR 72.9(c); and
(iii) The excess emissions requirements under 40 CFR 72.9(e)(1).

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NOx as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect.

If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan.

The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect.

(i) If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NOx for Phase II units with Group 1 boilers under 40 CFR 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, 40 CFR 76.7.
(ii) If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NOx for Phase II units with Group 1 boilers under 40 CFR 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, 40 CFR 76.7.

Certification

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

Name JOHN F. HANCOCK, DESIGNATED REPRESENTATIVE	
Signature J F Hancock	Date 12/12/96

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: [X] New [ ] Revised

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	ID#	ID#	ID#	ID#	ID#
	Type DBW	Type	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
(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)	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
(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)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

Plant Name (from Step 1) DEERHAVEN

STEP 2, cont'd.

	ID# B2	ID#	ID#	ID#	ID#	ID#
	Type DBW	Type	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

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

Name Randy L. Casserleigh, Designated Representative	
Signature	Date 12/19/97

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

City of Gainesville, GRU
Deerhaven Generating Station

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

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

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/ Year	Allowable Emissions Standard(s)	Allowable Emissions lbs./hour	Allowable Emissions TPY	Equivalent Emissions* lbs./hour	Equivalent Emissions* TPY	Regulatory Citation(s)	See Permit Condition(s)
003	Boiler No.1 (960 MMBtu/hr)	VE	Nos.1, 2, 4, 5, 6 F.O.	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
		VE	Used Oil	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
		VE	Nat.Gas/propane	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	**A.5**
	(Acid Rain Phase II Unit)	PM	Nos.1, 2, 4, 5, 6 F.O.	8760	0.1 lb/MMBtu	N/A	N/A	96.0	420.48	62-296.405(1)(b)	**A.8**
		PM	Used Oil	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	**A.8**
		PM	Nat.Gas/propane	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	**A.8**
		PM - SB**	Nos.1, 2, 4, 5, 6 F.O.	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		PM - SB**	Used Oil	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		PM - SB**	Nat.Gas/propane	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	**A.7**
		VE- SB**	Nos.1, 2, 4, 5, 6 F.O.	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		VE- SB**	Used Oil	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		VE- SB**	Nat.Gas/propane	3 hr/day	60%;100% - 4 six-min/periods			N/A	N/A	62-210.700(3)	**A.6**
		SO_2	Nos.1, 2, 4, 5, 6 F.O.	8760	2.75 lb /MMBtu	N/A	N/A	2,640.0	11,563.2	62-296.405(1)(c)1.j.	**A.9**
		SO_2	Used Oil	8760	2.75 lb /MMBtu	N/A	N/A	N/A	N/A	N/A	**A.9**
		SO_2	Nat.Gas/propane	8760	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
		% Sulfur	Nos. 4, 5, 6 F.O.	8760	max. sulfur content 2.5%, by wt.					Title V application	**A.10**
xxx	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 1-1A, Summary of Air Pollutant Standards and Terms

City of Gainesville, GRU
Deerhaven Generating Station

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

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

E. U. ID No.	Brief Description	Pollutant Name	Fuel(s)	Hours/ Year	Allowable Emissions Standard(s)	Allowable Emissions lbs./hour	Allowable Emissions TPY	Equivalent Emissions* lbs./hour	Equivalent Emissions* TPY	Regulatory Citation(s)	See Permit Condition(s)
006	Combustion Turbine No. 3	VE	Nat. Gas	3900	10% Opacity			N/A	N/A	BACT	C.4
		VE	Nos.1 and 2 F.O.	2000	10% Opacity			N/A	N/A	BACT	C.4
	74.4 MW	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					239.0	BACT	C.6
		SO_2	Gas	3900		29.0	57.0	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	53.0	53.0	BACT	C.6
		SO_2	Gas/Nos. 1 & 2 F.O	1900/2000			81.0		81.0	BACT	C.6
		PM_{10}	Nat. Gas	3900		7.0	14.0	7.0	14.0	BACT	C.6
		PM_{10}	Nos.1 and 2 F.O.	2000		15.0	15.0	15.0	15.0	BACT	C.6
		PM_{10}	Gas/Nos. 1 & 2 F.O	1900/2000			22.0		22.0	BACT	C.6
		SAM	Nat. Gas	3900		3.0	6.0	3.0	6.0	BACT	C.6
		SAM	Nos.1 and 2 F.O.	2000		6.0	6.0	6.0	6.0	BACT	C.6
		SAM	Gas/Nos. 1 & 2 F.O	1900/2000			9.0		9.0	BACT	C.6
		% sulfur	Nat. Gas							BACT	C.5
		% sulfur	Nos.1 and 2 F.O.	0.05%						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 No.: 0010006-001-AV
Facility ID No.: 0010006

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

E. U. ID No.	Brief Description	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date [2]	Min. Compliance Test Duration	CMS [1]	See Permit Condition(s)
003	Boiler No. 1	VE	Nos.1, 2, 4, 5, & No. 6 F.O.	DEP method 9	Annually [3]	31-Jan	60 Minutes	YES	A.17, 18, 23, 25, 27 & 28
			Natural Gas/propane	DEP method 9	N/A	N/A	N/A	YES	A.28
		PM	Nos. 1, 2, 4, 5,/No.6 F.O.	17, 5, 5B or 5F	Annually 3	31-Jan	60 minutes	No	A.19., 22.-25, 27, & 29
			Natural Gas/propane	17, 5, 5B or 5F	Annually 3	31-Jan	60 minutes	No	A.29
	Acid Rain Phase II Unit	As, Cd, Cr, Pb	Used Oil	SW-846					A.11
		Total Halogens	Used Oil	SW-846					A.11
		Flash Point	Used Oil	SW-846					A.11
		PCBs	Used Oil	SW-846					A.11
		SO_2	No. 6 F.O.	Fuel Sampling & Analysis				Yes	A.15, 20, 21
xxx	Coal Handling & Storage	VE		EPA method 9	N/A		30 Minutes		D.8, D.11, & 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, gaseous fuel in combination with liquid fuel is fired for no more than 400 hours, other than during startup; only liquid for no more than 400 hours, other than during startup

Table 2-1A, Summary of Compliance Requirements

City of Gainesville,GRU
Deerhaven Generating Station

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

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

E. U. ID No.	Brief Description	Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date [2]	Min. Compliance Test Duration	CMS [1]	See Permit Condition(s)
006	Combustion Unit 3	VE	Nos. 1 & 2 F.O./ Nat. Gas	EPA method 9	Annually[5,6]		30 Minutes	No	C.7, D.7, D.11
	74.4 MW	NOx	Nos. 1 & 2 F.O./ Nat. Gas	EPA method 20	Annually[6]		60 minutes	Yes	C.7
		SO_2/SAM	Nos. 1 & 2 F.O	ASTM 4057-88 and D2622-92, D4294-90, D2880-71or ASTM D129-91 (or equivalent)[4]				Yes	C.8, C.10, C.11, C.18
	Acid Rain	SO_2/SAM	Natural Gas					Yes	
	Phase II Unit	PM10	Nos. 1 & 2 F.O.	Fuel Sampling & Analysis - see SO_2/SAM methods					C.8, C.10, C.11, C.18
		PM	Natural Gas						
		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.8, B.11, D.5, 7 & 8
	2,428 MMBtu/hr								
	Acid Rain	PM	Coal, Gas, or Nos. 1 & 2 F.O	EPA 17, 5, 5B or 5F	Annually[3]		60 minutes	No	B.8, B.11, D.6
	Phase I Unit	NOx	Coal, Gas, or Nos. 1 & 2 F.O	EPA 7,7A,7C,7D, 7E	Annually		60 minutes	Yes	B.8, B.11
	Phase II Unit	SO_2	Coal, Gas, or Nos. 1 & 2 F.O	EPA 6,6A,6C	Annually		60 minutes	Yes	B.8, 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; gaseous fuel in combination with liquid fuel is fired for no more than 400 hours other than during startup; only liquid fuel is fired for no more than 400 hours, other than during startup.

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

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

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