Date: 9/29/97 11:09:56 AM
From: Elizabeth Walker TAL
Subject: New Posting
To: See Below

There is a new posting available on the Flrorida Website

DEERHAVEN STATION 0010006001AV Draft

The notification letter is encoded and attached. Please let me know if you have any questions.

Thanks
Elizabeth Walker

MEMORANDUM

TO: Scott M. Sheplak, P.E.
FROM: Teresa Heron T.H.
DATE: September 23, 1997

Re: Intent package for DRAFT Permit No.: 0010006-001-AV
Gainesville Regional Utilities
Deerhaven Generating Station

Permit Clock: NA

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

This facility consists of two steam boilers (Unit No. 1 and 2), two steam turbines, three simple-cycle combustion turbines (CT Nos. 1, 2, and 3), a Type I waste incinerator, a recirculating cooling water system, coal, brine salt, fly ash, and bottom ash storage and handling facilities, fuel oil storage tanks, water treatment facilities, and ancillary support equipment. Boiler No. 1 is fired with natural gas, No. 2 fuel oil, and No. 6 fuel oil including used oil fuel. Boiler No. 2 is fired with coal, natural gas, and No. 2 fuel oil. Combustion turbines (CT) No. 1, 2 and 3 are each fired with natural gas and No. 2 fuel oil, combustion turbines (CT Nos. 1, 2) burn diesel fuel .

No comments were received from the District and Branch offices.

This facility reported that each emissions unit was in compliance at the time of the application.

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

TH/
[electronic file name: 00100061.mem]

STATEMENT OF BASIS

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

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

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to 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.

This facility consists of two steam boilers (Unit No. 1 and 2), two steam turbines, three simple-cycle combustion turbines (CT Nos. 1, 2, and 3), a Type I waste incinerator, a recirculating cooling water system, coal, brine salt, fly ash, and bottom ash storage and handling facilities, fuel oil storage tanks, water treatment facilities, and ancillary support equipment. Boiler No. 1 is fired with natural gas, No. 2 fuel oil, and No. 6 fuel oil including used oil fuel. Boiler No. 2 is fired with coal, natural gas, and No. 2 fuel oil. Combustion turbines (CT) No. 1, 2 and 3 are each fired with natural gas and No. 2 fuel oil, combustion turbines (CT Nos. 1, 2) burn diesel fuel . Also, included in this permit are miscellaneous unregulated/exempt emissions units and/or activities.

Fossil fuel fired steam generator No. 1 is a nominal 88.0 megawatt (electric) steam generator designated as Boiler No. 1. The emissions unit is fired on No. 2 and No. 6 fuel oil including used oil fuel with a maximum heat input of 960 MMBtu per hour, and/or natural gas with a maximum heat input of 960 MMBtu per hour. 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. These emissions units are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input.

Fossil Fuel Steam Generator, Unit 2, rated at 295 MW, 2,428 MMBtu/hr, capable of burning coal, natural gas and number 2 fuel oil, with emissions exhausted through a 350 ft. stack. The emissions unit is regulated under Acid Rain, Phase II, and Rule 62-210.300, F.A.C., Permits Required and is subject to 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971. Particulate matter emissions are controlled by an electrostatic precipitator. The affected facility to which this subpart applies is fossil fuel steam generator, Unit 2. Fossil fuel fired steam generator Unit 2 began commercial operation in 1981.

The "Combustion Turbine No. 1" and "Combustion Turbine No. 2" are simple cycle combustion turbines. They are each rated at a maximum heat input of 298.1 million Btu per hour (MMBtu/hour) while being fueled by natural gas and 279 MMBtu/hour while being fueled by No. 2 fuel oil or diesel oil. Emissions from the combustion turbines are uncontrolled. These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. *Each combustion turbine has its own stack.* Combustion Turbine No. 1 and Combustion Turbine No. 2 began commercial operation in 1976.

Simple Cycle Gas Turbine, DHCT3, rated at 74 MW, 990.6 MMBtu/hr for number 2 fuel oil and 971.1 MMBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 52 ft. stack. This emissions unit is regulated under Acid Rain, Phase II and Rule 62-210.300, F.A.C., Permits Required and is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the simple cycle gas turbine, Unit 006. This unit underwent a BACT Determination dated April 11, 1995. BACT Limits were incorporated into the PSD permit, PSD-Fl-212 and Power Plant Conditions of Certification (PPCC), PA 74-04. Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 52 ft. stack. Emissions are controlled by dry low-NOx combustors, and by water injection when firing fuel oil. The turbine began commercial operation in 1995.

This emissions unit is a Type I waste incinerator manufactured by George L. Simmonds Co. (model number B- 215) and is designated as emission unit No. 004. Emissions from the incinerator are uncontrolled. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This emissions unit is not subject to 40 CFR 60, Subpart E, Standards of Performance for Incinerators. This emission unit is regulated under Rule 62-296.401(1) F.A.C. The incinerator's exhaust is ducted to the Steam Boiler No. 1 (Unit 1) stack.

Coal Handling and Storage Sources. This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This emissions unit is subject to applicable requirements of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants.

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

Also included in this permit are miscellaneous unregulated/exempt emissions units and/or activities.

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

P.E. Certification Statement

Permittee:
Gainesville Regional Utilities
Deerhaven Generating Station

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

Project type: Initial Title V Air Operation Permit

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

Scott M. Sheplak 09/25/97
Scott M. Sheplak, P.E. date
Registration Number: 0048866

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

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

September 23, 1997

Mr. Michael L. Kurtz
General Manager
City of Gainesville
Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida

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

Dear Mr. Kurtz:

One copy of the DRAFT Title V Air Operation Permit for the City of Gainesville, GRU located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County, is enclosed. The permitting authority's "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" " and the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" must be published as soon as possible upon receipt of this letter. This issue is important in order for you to receive your Title IV Acid Rain permit by January 1, 1998, pursuant to the Clean Air Act and Section 403.0872, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Scott M. Sheplak, P.E., at the above letterhead address. If you have any other questions, please contact Teresa Heron at 850/488-1344.

Sincerely,

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

CHF/sms/h

Enclosures

cc: Ms. Carla E. Pierce, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Yolanda Adams, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

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. John F. Hancock, Jr.
City of Gainesville
Gainesville Regional Utilities
Post Office Box 147117 (A132)
Gainesville, Florida 32614-

4a. Article Number
P 263 585 097

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

7. Date of Delivery

5. Received By: (Print Name)

6. Signature: (Addressee or Agent)
X

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

USPS GAINESVILLE 1997 103

Thank you for using Return Receipt Service.

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.
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- 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 Utilities
Post Office Box 147117 (A134)
Gainesville, Florida 32614-7117

4a. Article Number
P 263 585 096

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

7. Date of Delivery

5. Received By: (Print Name)

6. Signature: (Addressee or Agent)
X

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

PS Form 3811, December 1994 Domestic Return Receipt

USPS GAINESVILLE 1997 103

Thank you for using Return Receipt Service.

P 263 585 097

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

Sent to MR. John Hancock	
Street & Number P.O. Box 147117 (A132)	
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 9/30/97 - DRAFT PERMIT GRU Deerhaven ~~DOT~~ 0010006-001-AV	

PS Form 3800, April 1995

P 263 585 096

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 (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 9/30/97 DRAFT PERMIT GRU - Deerhaven Station ID#0010006-001-AV	

PS Form 3800, April 1995

In the Matter of an
Application for Permit by:

City of Gainesville
Gainesville Regional Utilities (GRU)
Post Office Box 147117, Station A-134
Gainesville, Florida 32614-7177
_____________________________/

DRAFT Permit No.: 0010006-001-AV
Deerhaven Generating Station
Alachua County

INTENT TO ISSUE TITLE V AIR OPERATION PERMIT

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V air operation permit (copy of DRAFT Permit enclosed) for the Title V source detailed in the application specified above, for the reasons stated below.

The applicant, City of Gainesville, GRU, applied on June 14, 1996, to the permitting authority for a Title V air operation permit for the Deerhaven Generating Station located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County.

The permitting authority has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. This source is not exempt from Title V permitting procedures. The permitting authority has determined that a Title V air operation permit is required to commence or continue operations at the described facility.

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

Pursuant to Sections 403.815 and 403.0872, F.S., and Rules 62-103.150 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-1344; Fax: 850/922-6979), within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-103.150(6), F.A.C.

The permitting authority will issue the Title V PROPOSED Permit, and subsequent Title V FINAL Permit, in accordance with the conditions of the enclosed Title V DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The permitting authority will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S. Mediation under Section 120.573, F.S., will not be available for this proposed action.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/488-9730; Fax: 850/487-4938). Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 (fourteen) days of receipt of this notice of intent. Petitions filed by any other person must be filed within 14 (fourteen) days of publication of the public notice or within 14 (fourteen) days of receipt of this notice of intent, whichever occurs first. 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 within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207, F.A.C.

A petition must contain the following information:

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

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

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

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

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

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

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the permitting authority to take with respect to the action or proposed action addressed in this notice of intent.

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

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

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

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

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

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

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

(e) The type of action requested;

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

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

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

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

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

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

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT (including the PUBLIC NOTICE and the DRAFT permit) and all copies were sent by certified mail before the close of business on 9/30/97 to the person(s) listed:

Mr. Michael L. Kurtz, General Manager/Responsible Official, GRU
Mr. John F. Hancock, Jr., Designated Representative

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT (including the PUBLIC NOTICE and the DRAFT permit) were sent by U.S. mail on the same date to the person(s) listed:

Mr. Thomas W. Davis, P.E., ECT
Ms. Yolanta E. Jonynas, GRU, Application Contact
Mr. Chris Kirts, NED
Ms. Patricia Reynolds, NEBD

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. Boutwell 9/30/97
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V air operation permit to City of Gainesville, GRU for the Deerhaven Generating Station located off U.S. 441 North/SR 20/SR 25, Gainesville, Alachua County. The applicant's name and address are: Mr. Michael L. Kurtz, General Manager/Responsible Official, Gainesville Regional Utilities, Post Office Box 147117 (A134), Gainesville, Florida 32202.

The permitting authority will issue the Title V PROPOSED Permit, and subsequent Title V FINAL Permit, in accordance with the conditions of the Title V DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

The permitting authority will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S. Mediation under Section 120.573, F.S., will not be available for this proposed action.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 904/488-9730; Fax: 904/487-4938). Petitions must be filed within 14 (fourteen) days of publication of the public notice or within 14 (fourteen) days of receipt of the notice of intent, whichever occurs first. 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 within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 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 Permit File Number, and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the permitting authority's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the permitting authority's action or proposed action; (d) A statement of the material facts disputed by the petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the permitting authority's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the permitting authority's action or proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the permitting authority to take with respect to the action or proposed action addressed in this notice of intent.

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

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

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

<u>Permitting Authority:</u>
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 904/488-1344
Fax: 904/922-6979

<u>Affected District/Local Program:</u>
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, FL 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4363

Northeast District Branch Office
101 NW 75 Street, Suite 3
Gainesville, FL 32607-1609
Telephone: 352/333-2850
Fax: 352/333-2856

The complete project file includes the DRAFT Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Scott M. Sheplak, P.E., at the above address, or call 850/488-1344, for additional information.

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

Initial Title V Air Operation Permit
DRAFT 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

and

Department of Environmental Protection
Northeast District Branch Office
101 NW 75 Street, Suite 3
Gainesville, FL 32607-1609
Telephone: 352/333-2850
Fax: 352/333-2856

Drafted September 15, 1997

Initial Title V Air Operation Permit
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Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

Permittee:
City of Gainesville, GRU
P.O. Box 147117 (A134)
Gainesville, Florida 32653

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

This permit is for the operation of the City of Gainesville's Deerhaven Generating Station. This facility is located at 10001 NW 13th Street, Gainesville, Alachua County; UTM Coordinates: Zone 17, 367.70 km East and 3292.60 km North; Latitude: 29° 45' 30" North and Longitude: 82° 23' 13" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to 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 E-1, List of Exempt Emissions Units and/or Activities
APPENDIX TV-1, TITLE V CONDITIONS (version dated 08/11/97)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (version dated 7/96)
BACT Determination dated 04/11/95
Phase II Acid Rain Application/Compliance Plan received 01/02/96
Alternate Sampling Procedure: ASP Number 97-B-01

Effective Date: January 1, 1998
Renewal Application Due Date: July 5, 2002
Expiration Date: December 31, 2002

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/kst/th

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two steam boilers (Unit No. 1 and 2), two steam turbines, three simple-cycle combustion turbines (CT Nos. 1, 2, and 3), a Type I waste incinerator, a recirculating cooling water system, coal, brine salt, fly ash, and bottom ash storage and handling facilities, fuel oil storage tanks, water treatment facilities, and ancillary support equipment. Boiler No. 1 is fired with natural gas, No. 2 fuel oil, and No. 6 fuel oil including used oil fuel. Boiler No. 2 is fired with coal, natural gas, and No. 2 fuel oil. Combustion turbines (CT) No. 1, 2 and 3 are each fired with natural gas and No. 2 fuel oil, combustion turbines (CT Nos. 1, 2) burn diesel fuel . Also, included in this permit are miscellaneous unregulated/exempt 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 ARMS ID No(s). and Brief Description(s).
E.U. ID No.

Brief Description

001	20.4 MW Simple Cycle Combustion Turbine No. 1
002	20.4 MW Simple Cycle Combustion Turbine No. 2
003	960 MMBtu/hr Steam Boiler No. 1
004	Type I Waste Incinerator
005	2,428 MM Btu/hr Steam Boiler No. 2
006	74.4 MW Simple Cycle Combustion Unit No. 3
xxx	Coal Handling and Storage Facilities

Unregulated Emissions Units and/or Activities

E.U. ID No.	**Brief Description of Emissions Units and/or Activity**
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
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

Section II. Facility-wide Conditions.

The following Conditions apply facility-wide:

1. APPENDIX TV-1, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-1, 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. Exempt Emissions Units and/or Activities. Appendix E-1, List of Exempt 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. **Not federally enforceable.** 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.
[Rule 62-296.320(1)(a), F.A.C.]

8. 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; and
  d. Confining abrasive blasting where possible.
[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996]

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-1, 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 Northeast District Air Section office and the Northeast District Branch 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

and

Department of Environmental Protection
Northeast District Branch Office
101 NW 75 Street, Suite 3
Gainesville, FL 32607-1609
Telephone: 352/955-2095
Fax: 352/377-5671

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
Operating Permits Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
001	Combustion Turbine No. 1
002	Combustion Turbine No. 2

These emissions units are simple cycle combustion turbines and are designated as "Combustion Turbine No. 1" and "Combustion Turbine No. 2". They are each rated at a maximum heat input of 298.1 million Btu per hour (MMBtu/hour) while being fueled by natural gas and 279 MMBtu/hour while being fueled by No. 2 fuel oil or diesel oil. Emissions from the combustion turbines are uncontrolled.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. *Each combustion turbine has its own stack.* Combustion Turbine No. 1 and Combustion Turbine No. 2 began commercial operation in 1976.}

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

Essential Potential to Emit (PTE) Parameters

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

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
001	298.1	Natural Gas
	279	No. 2 Fuel Oil or Diesel Fuel
002	298.1	Natural Gas
	279	No. 2 Fuel Oil or Diesel Fuel

[Rules 62-4.160(2), 62-210.200(PTE), F.A.C.; AO01-202759 and AO01-199846]

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

A.3. Methods of Operation - Fuels. Only natural gas, diesel fuel and distillate (No. 2) fuel oil shall be fired in the combustion turbines.
[Rule 62-213.410(1), F.A.C.; AO01-202759 and AO01-199846]

A.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year. The hours of operation shall be recorded.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AO01-202759 and AO01-199846]

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.; AO01-202759 and AO01-199846]

Excess Emissions

A.6. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.8. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

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

A.10. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. 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), F.A.C.]

A.11. Applicable Test Procedures.
(a) Required Sampling Time.
 2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable

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

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

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

A.12. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

A.13. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

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

A.15. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Northeast District Air Section office on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Units.

Subsection B. This section addresses the following emissions units.

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

Fossil fuel fired steam generator No. 1 is a nominal 88.0 megawatt (electric) steam generator designated as Boiler No. 1. The emissions unit is fired on No. 2 and No. 6 fuel oil including used oil fuel with a maximum heat input of 960 MMBtu per hour, and/or natural gas with a maximum heat input of 960 MMBtu per hour. 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): These emissions units are regulated under Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input.}

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

Essential Potential to Emit (PTE) Parameters

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

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
1	960 MMBTU/hr[1]	Natural Gas
	960 MMBTU/hr[2]	No. 6 Fuel Oil
	[3]	GRU Generated used oil[4]
	[5]	No. 2 fuel Oil

1 Basis: 0.82 MMCF/hr and 1170.7 MMBTU/MMCF. This basis is not to be construed as a permit limitation.
2 Basis: 129 bbls/hr. This basis is not to be construed as a permit limitation.
3 Include an estimate of the total quantity of used oil generated during the applicable calendar year in the AOR (Annual Operating Report)
4 Shall be burned in accordance with the applicable provisions of 40 CFR Part 266, Subpart E
5 Include the actual firing rate in the AOR.
Generator nameplate rating is 88.235 MW at a 1.0, Power factor.
Generator nameplate rating is 75.000 MW at a 0.85, Power factor.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, AO01-224219]

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

B.3. Methods of Operation - Fuels. The only fuels allowed to be burned are No. 2 and No. 6 fuel oil, natural gas, and on-specification used oil generated on site. Used oil containing PCBs above the detectable level cannot be used for startup or shutdown.
[Rule 62-213.410, F.A.C.; and AO01-224219]

B.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; and, AO01-224219]

Emission Limitations and Standards

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

B.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.;and, AO01-224219]

B.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C; and, AO01-224219]

B.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input , as measured by applicable compliance methods.
[Rules 62-296.405(1)(b) and 62-296.702(2)(a), F.A.C.; and, AO01-224219]

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

B.9. Sulfur Dioxide. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input , as measured by applicable compliance methods. Any calculations used to demonstrate compliance shall be based solely on the Btu value and the percent sulfur of the liquid fuel being burned.
[Rules 62-213.440 and 62-296.405(1)(c)1.b., F.A.C.; and, AO01-224219]

B.10. Sulfur Dioxide - Sulfur Content. The sulfur content of the as fired No. 6 fuel oil shall not exceed 2.5 percent, by weight, and 0.5 percent by weight for No. 2 fuel oil. See specific condition **B.21**.
[Rule 62-296.405(1)(e)3., F.A.C]

B.11. "On-Specification" Used Oil. Only "on-specification" used oil generated on site shall be fired in this emission unit. The total quantity allowed to be fired in this emission unit shall be reported each calendar year. "On-specification" used oil is defined as used oil that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See specific conditions **B.30., B.34.** and **B.35.**

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 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
[40 CFR 279.11]

Excess Emissions

B.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.]

B.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.]

B.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

B.15. Sulfur Dioxide. **The permittee elected to demonstrate compliance using fuel sampling and analysis.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **B.20.** and **B.21**.
[Rule 62-296.405(1)(f)1.b., F.A.C.; and, AO01-224219]

B.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.}

B.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. The visible emission test must be concurrent with one particulate matter test run. See specific condition **B.18**.

[Rule 62-296.405(1)(e)1., F.A.C., and AO01-224219]

B.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.]

B.19. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 (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.]

B.20. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance using fuel sampling and analysis.** See specific condition **B.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.; and, AO01-224219]

B.21. For each emissions unit, the following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition(s), to analyze a representative sample of the blended fuel following each fuel delivery.
b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
c. The analyses of the No. 6 fuel oil, as received from the supplier, shall include the following:
   (1) Density (ASTM D 1298-80 or the latest edition,).
   (2) Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
   d. Utilize the above information in a., b. and c., to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; and, AO01-224219]

B.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.]

B.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.]

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

B.25. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of

particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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

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

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

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

(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.]

B.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.; and, AO01-224219]

B.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.

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

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

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

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

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

9. The owner or operator shall notify the Northeast District Air Section, 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 Northeast District Air Section, 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 Northeast District Air Section.

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

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

B.28. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

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

B.29. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

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

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

B.30. Compliance with the "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. See specific conditions **B.11., B. 34.** and **B.35.**
[Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Record keeping and Reporting Requirements

B.31. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Northeast District Air Section 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 D.E.P.
[Rule 62-210.700(6), F.A.C.]

B.32. Submit to the Northeast District Air Section 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.]

B.33. Test Reports.

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

(b) The required test report shall be filed with the D.E.P. 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 D.E.P. 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.]

B.33a. Fuel Analysis Report. The owner or operator shall submit to the Department a copy of the Certified ASTM analysis and the sulfur dioxide emission calculations. Fuel oil test report, including fuel oil heat content

shall be submitted to the Department with each test report.
[AO01-224219]

B.34. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in this emissions unit. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **B.11., B.30.** and **B. 35.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

B.35. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Boiler No. 1 during the calendar year. See specific conditions **B.11., B.30.** and **B.34.**
[Rule 62-213.440(1)(b)2.b., F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
004	Incinerator

This emissions unit is a Type I waste incinerator manufactured by George L. Simmonds Co. (model number B-215) and is designated as emission unit No. 004. Emissions from the incinerator are uncontrolled.

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

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

Essential Potential to Emit (PTE) Parameters

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

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

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

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

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

C.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. The hours of operation shall be recorded.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and AO01-202758]

Emission Limitations and Standards

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

C.5. Visible Emissions. No visible emissions (5 percent opacity) are allowed from this emission unit except that visible emissions not exceeding 20 percent opacity are allowed for up to three (3) minutes in any one hour period.
[Rule 62-296.401, F.A.C.; and AO01-202758.]

Excess Emissions

C.6. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.8. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

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

C.10. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. 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), F.A.C.]

C.11. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60)

minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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

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

C.12. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

C.13. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

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

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

C.14. Visible Emissions Testing - Annual. Annual emissions compliance testing for visible emissions is not required for this emissions unit due to the use of emissions unit 003 (Boiler No. 1) stack.
[AO01- 202758]

Recordkeeping and Reporting Requirements

C.15. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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.]

C.16. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Units.

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
005	Fossil Fuel Steam Generator, Unit 2, rated at 295 MW, 2,428 MMBtu/hr, capable of burning coal, natural gas and number 2 fuel oil, with emissions exhausted through a 350 ft. stack.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II, and Rule 62-210.300, F.A.C., Permits Required and is subject to 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971. Particulate matter emissions are controlled by an electrostatic precipitator. The affected facility to which this subpart applies is fossil fuel steam generator, Unit 2. Fossil fuel fired steam generator Unit 2 began commercial operation in 1981.}

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

Essential Potential to Emit (PTE) Parameters

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

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
005	591	Natural Gas
	900	Fuel Oil
	2,428	Coal

Generator nameplate rating is 295 MW at a power factor of 1.0
Generator nameplate rating is 250.75 MW at a power factor of 0.85
Maximum heat input is 2,214 MMBtu/hr @ 235 MW
[Rules 62-4.160(2) and 62-210.200(PTE) F.A.C.]

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **F.14.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are coal, natural gas and number 2 fuel oil.
[Rule 62-213.410, F.A.C., PA 74-04, and applicant request in Title V application received June 14, 1996]

Emission Limitations and Standards

D.4. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.
[Rule 62-210.700(3), F.A.C., Note: Unit 2 has an operational continuous opacity monitor.]

D.5. 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.]

D.6. 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) 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)]

D.7. 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) derived from liquid fossil fuel.
(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel, maximum three hour average.
(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
[40 CFR 60.43(a) & (c)]

D.7a. Sulfur Dioxide- Sulfur Content. The percent maximum allowable sulfur content of coal consumed shall be limited as follows: *% Maximum allowable sulfur content = 6.3 X 10* $^{-5}$ *BTU per lb of coal.* However, the applicant may petition the Department to revise this condition by installing a flue gas desulfurization unit that will insure compliance with Rule 17-296.405, F.A.C. The boiler shall not be operated unless this condition is complied with.
[Power Plant Certification PA 74-04]

D.7b. 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]

D.8. Pursuant to 40 CFR 60.44 Standard For Nitrogen Oxides.
(a) On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel.
(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from liquid 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:

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

where:

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

Test Methods and Procedures

D.9. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

D.10. Sulfur Dioxide. **The permittee elected to use fuel sampling and analysis in lieu of installing a continuous monitoring system for SO_2 as required by the NSPS.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device.

The following fuel sampling and analysis program shall be used to monitor sulfur dioxide emissions:

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

[Rule 62-213.440, F.A.C., and 40 CFR 60.45(b)(2)]

D.11. 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, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(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 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each run using the following equation:

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

E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
$\%\ O_2$ = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

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

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

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the 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 shall be used to determine opacity.

(4) Method 6 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 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 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)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) 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 40 CFR 60.46 or in other sections 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 shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b) (2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209\ (F_{da}\ /\ F_{ca})$, then the following procedure shall be followed:

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

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if 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).

(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)]

Monitoring of Operations

D.12. Record Heat Input. The owner or operator shall make and maintain records of the heat input to the boiler from all fuels at all times to demonstrate compliance with specific condition **D.3** of this permit.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

D.13. Annual Tests Required - PM, VE, SO_2 and NOx. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for particulate matter emissions, visible emissions, sulfur dioxide and nitrogen oxides shall be performed annually, no later than August 1st of each year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

D.14. 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).
(b) Not applicable.
(c) For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:
[In parts per million]

Fossil fuel	Span value for sulfur dioxide	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) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.
(d) [Reserved]

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

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

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

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

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

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

where:

E, C, F_c and %CO_2 are determined under 40 CFR 60.45(f).

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

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

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

(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).

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

(i) For *anthracite coal* as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), $F = 2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c = 0.532 \times 10^{-17}$ scm CO_2 /J (1,980 scf CO_2 /million Btu).

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

(iii) For *liquid fossil fuels* including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).

(iv) For *gaseous fossil fuels*, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm 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.

(v) For *bark* $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2 /J (1,840 scf CO_2 / million Btu). For *wood residue* other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and Fc $= 0.494 \times 10^{-7}$ scm CO_2 /J (1,860 scf CO_2 / million Btu).

(vi) For *lignite coal* as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), $F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/million Btu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2 /J (1,920 scf CO_2 /million Btu).

(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):

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

$$F_c = \frac{2.0\times10^{-5}\ (\text{pct. C})}{GCV}$$

(SI units)

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

(English units)

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

(SI units)

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV}$$

(English units)

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

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

(iii) For affected facilities which fire *both fossil fuels and nonfossil fuels*, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing *combinations of fossil fuels or fossil fuels and wood residue*, the F or F_c

factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

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

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 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). 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.
(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.
[40 CFR 60.45(g)]

Emission Control System

D.15. Prior to operation of the source, the owner or operator shall submit to the Department a standardized plan or procedure that will allow GRU to monitor emission control equipment efficiency and enable GRU to return malfunctioning equipment to proper operation as expeditiously as possible.
[Power Plant Certification PA-04]

Reporting

D.16. The permittee shall maintain a daily log of fuels used and copies of fuels analyses containing information on sulfur content, ash content and heating values to facilitate calculations of emissions.
[Power Plant Certification PA 74-04]

Other NSPS Subpart D Conditions

D.17. Pursuant to 40 CFR 60.41 Definitions. As used in 40 CFR 60 Subpart D, all terms not defined in 40 CFR 60.41 shall have the meaning given them in the Act, and in Subpart A of this part.

<u>**Common Conditions**</u>

D.18. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

D.19. This emissions unit is also subject to conditions **G.1** through **G.6** contained in **Subsection G. NSPS Common Conditions.**

Section III. Emissions Units.

Subsection E. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
006	Simple Cycle Gas Turbine, DHCT3, rated at 74 MW, 990.6 MMBtu/hr for number 2 fuel oil and 971.1 MMBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 52 ft. stack.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II and Rule 62-210.300, F.A.C., Permits Required and is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the simple cycle gas turbine, Unit 006. This unit underwent a BACT Determination dated April 11, 1995. BACT Limits were incorporated into the PSD permit, PSD-FI-212 and Power Plant Conditions of Certification (PPCC), PA 74-04. Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 52 ft. stack. Emissions are controlled by dry low-NOx combustors, and by water injection when firing fuel oil. The turbine began commercial operation in 1995.}

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

Essential Potential to Emit (PTE) Parameters

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

E.U. ID No.	MMBtu/hr Heat Input	Fuel Type
006	971.1*	Natural Gas
	990.6*	No. 2 Fuel Oil

* Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.
Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP).
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., PA 74-04 and PSD-FL-212]

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

E.3. Methods of Operation - Fuels. Only natural gas and number 2 fuel oil shall be fired in the combustion turbine.
{Note: The limitations of specific conditions **E.6** and **E.7** are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334.}
[Rule 62-213.410, F.A.C.]

E.4. Fuel Oil Consumption Limits. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FI-212]

Emission Limitations and Standards

E.5. Visible Emissions Visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

[PA 74-04 and PSD-FL-212]

E.6. Sulfur Dioxide - Sulfur Content. The No. 2 fuel oil sulfur content shall not exceed 0.05 percent, by weight. See specific condition **E.12.** The natural gas sulfur content shall not exceed 10 grains per hundred cubic feet (standard conditions). See specific condition **E.11.**
{Note: The limitation of specific condition **E.6.** is more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334. The sulfur limitation on natural gas has been added to assure compliance with 40 CFR 60.333.}
[Rules 62-4.070(3) and 62-213.440, F.A.C.; PA 74-04 and PSD-FL-212]

E.7. Allowable Emissions. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, 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, and malfunction pursuant to Rule 62-210.700, F.A.C.:

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 emission 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)(d)
			Combined(c)	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)	6(b)(d)
			Combined(c)	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 fuel sulfur analysis.

The following estimated potential emissions are listed for inventory purposes:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0.004854

Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

** 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 for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

{Note: The limitations of specific condition **E.7** are more stringent than the NSPS nitrogen oxides limitation and thus ensure compliance with 40 CFR 60.332 and 60.334.}
[PA 74-04 and PSD-FL-212) and requested by applicant in the initial Title V permit application received June 14, 1996]

Test Methods and Procedures

E.8. Annual Compliance Tests. Except as provided in specific conditions **F.6** of this permit, emission testing for visible emissions and nitrogen oxides shall be performed annually, no later than August 1st of each year, in accordance with specific condition **E.10**, 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.

If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C., PA 74-04 PSD-FL-212]

E.9. Testing for PM, PM, 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 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 **E.12.** for the sulfur content of liquid fuels and gaseous fuels. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) .
[Rules 62-4.070(3) and 62-213.440, F.A.C., PA 74-04 and PSD-FL-212]

E.10. 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 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]

E.11. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the *liquid fuel* sulfur limit by fuel sampling and analysis. See specific conditions **E.6. and E.12.** The permittee shall demonstrate compliance with the *gaseous fuel* sulfur limit via record keeping. See specific condition **E.15.**
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

E.12. Fuel Sampling & Analysis - Sulfur. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for *liquid fuels* using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-9, or the latest edition(s), to analyze a representative sample of the blended fuel following each fuel delivery.

b. Record daily the amount of each fuel fired, the density of each fuel, heating value, and the percent sulfur content by weight of fuel oil.

c. Determine and record the as-fired fuel sulfur content, percent by weight, for *gaseous fuels* using either ASTM D1072-80, D3031-81, D4084-82 or D3246-81, or the latest edition(s).

The permittee is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e)
[Rule 62-213.440, F.A.C., PA 74-04 and PSD-FL-212]

Monitoring of Operations

E.13. 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 in accordance with the requirements of 40 CFR 75.
[PA 74-04 , PSD-FL-221 and requested by applicant in the initial Title V permit application received June 14, 1996]

E.14. 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 following the format of 40 CFR 60.7 . Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. 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 accordance with 40 CFR 60, Subpart GG, and 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 levels 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 40 CFR 60.335(c) (2) will be replaced by certification tests of the NOx CEMS.
{Note: The requirements of specific condition **E.14** are more stringent than the NSPS monitoring provisions and thus assure compliance with 40 CFR 60.334 and 60.335.}
[Rules 62-4.070(3), 62-213.440, F.A.C., PA 74-04 and PSD-FL-212]

E.14.a. The continuous emission monitor must comply with Rule 62-297.500, 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.
[Rules 62-4.070(3), 62-213.440, F.A.C., PA 74-04 and PSD-FL-212]

E.14.b. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_X combustor on the DHCT3 for NO_X control when firing natural gas. Control of NO_X when firing No. 2 fuel oil shall be accomplished by water injection.
[Rules 62-4.070(3), 62-213.440, F.A.C., PA 74-04 and PSD-FL-212]

<u>Record Keeping and Reporting Requirements</u>

E.15. <u>Natural Gas Sulfur Content Records Required</u>. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier at minimum twice each month. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

E.16. <u>Additional Reports Required</u>. The owner or operator shall report the following with the Air Operating Report (AOR): sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage (single fired and co-fired).
[Rule 62-210.370(3), F.A.C., PA 74-04 and PSD-FL-212]

E.17. <u>Custom Schedule.</u> The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) . Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 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]

<u>Other Conditions</u>

E.18. These emissions units are also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

E.19. These emissions units are also subject to condition **G.1** through **G.6** contained in **Subsection G. NSPS Common Conditions.**

Section III. Emissions Units.

Subsection F. Common Conditions.

E.U. ID No.	**Brief Description**
005	Fossil Fuel Steam Generator, Unit 2, rated at 295 MW, 2,428 MMBtu/hr, capable of burning coal, natural gas and number 2 fuel oil, with emissions exhausted through a 350 ft. stack.
006	Simple Cycle Gas Turbine, DHCT3, rated at 74 MW, 990.6 MMBtu/hr for number 2 fuel oil and 971.1 MMBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 52 ft. stack.
-xxx	Coal Handling and Storage Facilities

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

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. The emission unit 005 (Boiler No.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 fuel oil.
[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 purposes only. This table does not supersede any of the terms or conditions of this permit.}

Excess Emissions

F.2. 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.]

F.3. 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.]

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

Monitoring of Operations

F.5. 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.}

F.6. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or
b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
a. Visible emissions, if there is an applicable standard;
b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each

formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

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

F.7. When PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

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

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

F.8. Visible Emissions- Boilers. When VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for the emissions units while burning:

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

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

F.9. Visible Emissions - Turbines. The test method for visible emissions for emissions units 001 and 002 (DHCT1 and DHCT2) and 006 (DHCT3) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.

[Rules 62-204.800 and 62-297.401, F.A.C.]

F.10. Visible Emissions - Boilers, Units No. 1 and 2 . The test method for visible emissions for emissions units 003 (Unit No. 1) and 005 (Unit No.2) 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 **F.11.**

[Rules 62-296.405(1)(e)1. and 62-297.401, F.A.C.]

F.11. 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.]

F.12. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

F.13. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

F.14. 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.]

F.15. Applicable Test Procedures.

(a) Required Sampling Time.

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

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

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

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

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

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

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

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

F.16. 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.]

Record Keeping and Reporting Requirements

F.17. Malfunctions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Northeast District Air Section 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 Northeast District Air Section.

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

F.18. Excess Emissions - Report. Submit to the Northeast District Air Section a written report of emissions in excess of emission limiting standards as set forth in this permit, 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.

[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

F.19. 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 Air Section on the results of each such test.

(b) The required test report shall be filed with the Northeast District Air Section 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 Northeast District Air Section 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 G. 40 CFR 60, NSPS General Conditions.

E.U. ID No.	Brief Description
005	Fossil Fuel Steam Generator, Unit 2, rated at 295 MW, 2,428 MMBtu/hr, capable of burning coal, natural gas and number 2 fuel oil, with emissions exhausted through a 350 ft. stack.
006	Simple Cycle Gas Turbine, DHCT3, rated at 74 MW, 990.6 MMBtu/hr for number 2 fuel oil and 971.1 MMBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 52 ft. stack.
xxx	Coal Handling and Storage Facilities

{Note: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected units to which this subpart applies are fossil fuel steam generator, Unit No. 2 , the coal handling and storage facilities and the simple cycle gas turbine, DHCT3.}

The following Conditions apply to the NSPS emissions units listed above:

G.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)) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action

taken or preventative measures adopted.

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

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

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

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

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

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance]

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

G.2. <u>Pursuant to 40 CFR 60.8 Performance Tests.</u>

(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]

G.3. <u>Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.</u>

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by 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 Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(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 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), 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 Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11]

G.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]

G.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.
(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), 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), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(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), 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) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(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) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(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 recorder 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]

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

The materials listed below are incorporated by reference in the corresponding sections noted.

[Note: The remainder of this section has not been reproduced in this permit for brevity. See 40 CFR 60.17 for materials incorporated by reference.]

[40 CFR 60.17]

Section III. Emissions Unit(s) and Conditions.

Subsection H. This section addresses the following emissions units.

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

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This emissions unit is subject to applicable requirements of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants.}

SUMMARY OF COAL HANDLING SOURCES

Source Description	Emission Point ID	Emission Type
Coal Handling - Railcar Unloading; Bottom Discharge	CH-001	F
Coal Handling - Belt Conveyor 2 to Belt Conveyor 3B	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 - Conveyor 3A to Ready Storage Pile	CH-006	F
Coal Storage - Conveyor 3 B to 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; Belt Conveyor 4A to Surge Bin	CH-10A	F
Coal Handling - Crusher Building; Surge Bin to Crusher Feeder	CH-010B	F
Coal Handling - Crusher Building; Crusher Feeder to Crusher	CH-010C	F
Coal Handling - Crusher Building: Crusher to Belt Conveyor 5A	CH-010D	F
Coal Handling - Coal Bunker Building; Belt Conveyor 5A to Belt Conveyor 6A	CH-011A	F
Coal Handling - Coal Bunker Building; Belt Conveyor 6A to Bunkers	CH-011B	F

Emissions Unit(s) Control Equipment

Dust Control by application of chemical dust suppressant (CH-001, CH-002, and CH-003)
Telescoping chute (CH-004 and CH-005)
Baghouse (CH-010 and CH-011)
Enclosure of crushing and bunkering equipment

Essential Potential to Emit (PTE) Parameters

Permitted Capacity.

H.1. The maximun coal throughput rate shall not exceed 660,000 tons per year.
[Rules 62-4.160(2) F.A.C., 62-210.200 (PTE) F.A.C.; and Title V application received June 14, 1997]

Particulate emissions from the coal handling facilities

H.2. The applicant 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]

Coal Characteristics and Contracts

H.3. Before approval can be granted by the Department for use of control devices, characteristics of the coal to be fired must be known. Therefore, before these approvals are granted, the applicant must submit to the Department copies of coal contracts which should be include the expected sulfur content, ash content, and heat content of the coal to be fired. These data will be used by the Department in its evaluation of the adequacy of the control devices. Also, the applicant must demonstrate the ability to acquire a low sulfur coal supply of sufficient length to enable the installation of sulfur removal equipment if the supplies of low sulfur coal should not become available or be discontinued. Therefore, the coal contracts must be for a period of at least five (5) years from the date of start-up of the boiler.

As an alternative to the submittal of contracts for purchase of coal under the above condition, the applicant may submit the following information:

1. The name of the coal supplier;
2. The sulfur content, ash content, and heat content of the coal as specified in the purchase contracts;
3. The location of the coal deposits covered by the contract (including mine name and seam);
4. The date by which the first delivery of coal will be made;
5. The duration of the contract; and
6. An opinion of counsel for the applicant that the contract(s) are legally binding.

[Power Plant Certification PA 74-04]

H.4. The applicant must submit to the Department within five (5) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to the inadequate to meet the visible emission limit specified above.
[Power Plant Certification PA 74-04]

H.5. Reporting. Beginning one month after certification the applicant shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to the Siting Coordination Office, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.
[Power Plant Certification PA 74-04]

Test Methods and Procedures

H.6. Visible Emissions - The test method for visible emissions for this emissions unit shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-297.401, F.A.C.; Subpart Y, 40 CFR 60.254 (b) and 40 CFR 60.11]

Other Conditions

H.7. These emissions units are also subject to conditions **F.2** through **F.19 (except F.7, F.8., F.9, F.10. and F.16.)** contained in **Subsection F. Common Conditions.**

H.8. These emissions units are also subject to condition **G.1** through **G.4** and **G.6**. contained in **Subsection G. NSPS Common Conditions.**

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	Boiler No.1 - DH Unit No.1
005	Boiler No.2 - DH Unit No.2
006	Combustion Turbine No. 3 - DHCT3

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

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

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

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002
003	B1	**SO2 Allowances, under Table 2 or 3 of 40 CFR Part 73**	98*	98*	98*
005	B2	**SO2 Allowances, under Table 2 or 3 of 40 CFR Part 73**	8201*	8201*	8201*
		NOx limit	**	**	**
006	CT3	**SO2 Allowances, under Table 2 or 3 of 40 CFR Part 73**	0*	0*	0*

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

**If applicable, by January 1, 1999, this Part will be reopened to add NOx requirements in accordance with the regulations implementing section 407 of the Clean Air Act.

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

A.4. Comments, notes, and justifications:
  a. Letter dated January 9, 1996 amending original application; and
  b. Letter dated January 26, 1996 reflecting CT3 designation.

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

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

The emissions units listed below is regulated under Acid Rain Part, Phase I

E.U. ID No.	Brief Description
005	Boiler No. 2 - DH Unit No.2

The provisions of the federal Acid Rain, Phase I permit(s), including Early Election Plans for NO_X, govern(s) the above listed emissions unit(s) from the date of issuance of this Title V permit through December 31, 1999. The provisions of the Phase II permit govern(s) those emissions unit(s) from January 1, 2000 through the expiration date of this Title V permit. The Phase II permit governs all other affected units for the effective period of this permit.

B.1. The Phase I permit(s), including Early Election Plans for NO_X, issued by the U.S. EPA, is a part of this permit. The owners and operators of these Phase I acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:
 a. Phase I permit dated 03/27/97.
[Chapter 62-213, F.A.C.]

B.2. Comments, notes, and justifications: none

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

City of Gainesville, GRU
Deerhaven Generating Station

DRAFT 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
xxx	Pneumatic Transfer of Fly Ash from DH-2 to Fly Ash Silo
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
xxx	Emergency Generators
xxx	Heating units and general purpose internal combustion engines
xxx	Surface coating operations utilizing 6.0 gallons per day less, averaged monthly, of coatings containing greater than 5.0 percent VOC's, by volume.
xxx	Degreasing units using heavier-than-air vapors exclusively, except any unit using or emitting any substance classifed as a hazardous air pollutant.

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Appendix E-1, List of Exempt Emissions Units and/or Activities.

City of Gainesville, GRU
Deerhaven Generating Station

DRAFT Permit No.: 0010006-001-AV

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Full 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 whether a facility containing such emissions units or activities would be subject to any applicable requirements. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., are also exempt from the permitting requirements of Chapter 62-213, F.A.C., provided such emissions units and activities also meet the exemption criteria of Rule 62-213.430(6)(b), F.A.C. The below listed emissions units and/or activities are hereby exempt 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. No. 2 and No. 6 fuel oil 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 No. 1. This activity occurs once every three to five years or longer.

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

City of Gainesville, GRU
Deerhaven Generating Station

DRAFT 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)
-001	Combustion Turbine No.1	VE	No. 2 F.O.	8760	20% - 1 two min. period/hr.			N/A	N/A	62-296.320(4)(b)	A.5.
	and	VE	Diesel Oil	8760	20% - 1 two min. period/hr.			N/A	N/A	62-296.320(4)(b)	A.5.
-002	Combustion Turbine No. 2	VE	Natural Gas	8760	20% - 1 two min. period/hr.			N/A	N/A	62-296.320(4)(b)	A.5.
-003	Boiler No.1 (960 MMBtu/hr)	VE	No. 2 & No.6 F.O.	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	B.5.
	88 MW Turbine-generator	VE	Used Oil	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	
		VE	Natural Gas	8760	20%; 40% - 1 two min. period/hr.			N/A	N/A	62-296.405(1)(a)	B.5.
	Acid Rain Phase II Unit	PM	No. 2 & No.6 F.O.	8760	0.1 lb/MMBtu	N/A	N/A	96.0	420.48	62-296.405(1)(b)	B.7.
		PM	Used Oil	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	B.7
		PM	Natural Gas	8760	0.1 lb/MMBtu	N/A	N/A	N/A	N/A	62-296.405(1)(b)	B.7.
		PM - SB**	No. 2 & No.6 F.O.	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	B.8.
		PM - SB**	Used Oil	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	B.8.
		PM - SB**	Natural Gas	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62-210.700(3)	B.8.
		VE- SB**	No. 2 & No.6 F.O.	3 hr/day	60 % - four (4) six-min/periods			N/A	N/A	62-210.700(3)	B.6.
		VE- SB**	Used Oil	3 hr/day	60 % - four (4) six-min/periods			N/A	N/A	62-210.700(3)	B.6.
		VE- SB**	Natural Gas	3 hr/day	60 % - four (4) six-min/periods			N/A	N/A	62-210.700(3)	B.6.
		SO_2	No. 2 & No.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	B.9.
		SO_2	Used Oil	8760		N/A	N/A	N/A	N/A	N/A	B.11.
		SO_2	Natural Gas	8760	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		% Sulfur	No. 6 F.O.	8760	max. sulfur content 2.5%, by wt.					Title V application	B.10.
-004	Incinerator- Type I	VE	Rubbish/Gas	8760	5% opacity.			N/A	N/A	62-296.401(a)	C.5.
		VE	Rubbish/Gas	8760	20% - 1 three min period/hr.			N/A	N/A	62-296.401(a)	C.5.
xxx	Coal Handling and Storage	VE		8760	Not to exceed 20% opacity			N/A	N/A	40 CFR 60.252.(c)	H.2

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

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

City of Gainesville, GRU
Deerhaven Generating Station

DRAFT 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	74.4 MW	VE	Gas or No.2 F.O	3900	10% opacity			N/A	N/A	BACT	E.7
	Combustion Turbine No.3	NOx	Gas	3900	15 ppmvd @ 15 % Oxygen			58.0	113.0	BACT	E.7
		NOx	No.2 Fuel Oil	2000	42 ppmvd @ 15 % Oxygen			184.0	184.0	BACT	E.7
	Acid Rain Phase II Unit	NOx	Gas and No.2 F.O	1900/2000					239.0	BACT	E.7
		SO_2	Gas	3900		29.0	29.0	29.0	57.0	BACT	E.7
		SO_2	No.2 F.O	1900		53.0	53.0	53.0	53.0	BACT	E.7
		PM_{10}	Gas	3900		7.0		7.0	14.0	BACT	E.7
		PM_{10}	No.2 F.O.	2000		15.0	15.0	15.0	15.0	BACT	E.7
		SAM	Gas	3900		3.0		3.0	6.0	BACT	E.7
		SAM	No. 2 F.O.	2000		6.0	6.0	6.0	6.0	BACT	E.7
		SAM	Gas and No.2 F.O	1900/2000					9.0	BACT	E.7
005	Boiler No.2	VE	Coal/Gas/No.2 F.O	8760	20%; 27% - 1 six min. period/hr.			N/A	N/A	40 CFR 60.42(a)1&2	D.6
	2,428 MMBtu/hr)	VE- SB	Coal/Gas/No.2 F.O	3 hr/day	60 % - four (4) six-min/periods					62.210.700 (3)	D.4
	295 MW Generator	PM	Coal/Gas/No.2 F.O	8760	0.1 lb/MMBtu	N/A	N/A	261.1	1,063.45	40 CFR 60.42(a)1&2	D.6
		PM - SB	Coal/Gas/No.2 F.O	3 hr/day	0.3 lb/MMBtu	N/A	N/A	N/A	N/A	62.210.700 (3)	D.5
	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)	D.7
		SO_2	No.2 Fuel Oil	8760	0.8 lb /MMBtu	N/A	N/A	1,942.4	8,507.71	40 CFR 60.43(a)&(c)	D.7
		% sulfur	Coal	Maximum allowable sulfur content: 6.3 X 10 BTU per lb coal						PA74-04	D.7
		NOx	Coal	8760	0.7 lb /MMBtu	N/A	N/A	1,699.6	7,444.25	40 CFR60.44(a)&(b)	D.8
		NOx	No.2 Fuel Oil	8760	0.3 lb /MMBtu	N/A	N/A	728.4	3,190.39	40 CFR60.44(a)&(b)	D.8
		NOx	Natural Gas	8760	0.2 lb /MMBtu	N/A	N/A	485.60	2,126.92	40 CFR60.44(a)&(b)	D.8

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

[electronic file name: 0010006.xls]

Table 2-1, Summary of Compliance Requirements

City of Gainesville,GRU
Deerhaven Generating Station

DRAFT 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)
-001	Combustion Unit No. 1	VE	No. 2 F.O.	EPA method 9	Annually [4]	1-Apr	60 Minutes	No	A.17., 18., 23., 25., 27. & 28.
	and	VE	Natural Gas	EPA method 9	N/A	N/A	N/A	No	A.13
-002	Combustion Unit No. 2	VE	Diesel Fuel	EPA method 9	Annually [4]	1-Apr	60 Minutes	No	A.17., 18., 23., 25., 27. & 28.
-003	Boiler No. 1	VE	No. 6 F.O.	EPA method 9	Annually [3]	31-Jan	60 Minutes	No	B.17., 18., 23., 25., 27. & 28.
	88 MW Turbine-Generator		Natural Gas	EPA method 9			60 Minutes	No	B.28.
	Acid Rain Phase II Unit	PM	No. 2 and No.6 F.O.	17, 5, 5B or 5F	Annually [3]	31-Jan	1 Hour	No	B.19., 22.-27., & 29.
			Natural Gas	17, 5, 5B or 5F	Annually [3]	31-Jan	1 Hour	No	B.29
		As, Cd, Cr, Pb	Used Oil	ASTM Standard D-140-70					B.11.
		Total Halogens	Used Oil	ASTM Standard D-140-70					B.11.
		Flash Point	Used Oil	ASTM Standard D-140-70					B.11.
		PCBs	Used Oil	ASTM Standard D-140-70					B.11.
		SO_2	No. 6 F.O.	Fuel Sampling & Analysis As Fired				Yes	B.15., 20. & 21.
-004	Incinerator - Type I	VE	Rubbish/Gas	EPA method 9	Annually [5]		60 Minutes	No	C.13., 14., & 15.-20.
xxx	Coal Handling and Storage	VE		EPA method 9	Annually		60 Minutes		H.6.

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 fuel oil is fired less than 400 hours. Visible emission test must be concurrent with one particulate matter test run.

[4] 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.

[5] Test not required due to exhausting thru Boiler No.1 (Unit No.1) stack

[electronic file name: 0010006.xls]

Table 2-1A, Summary of Compliance Requirements

City of Gainesville,GRU
Deerhaven Generating Station

DRAFT 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 No. 3	VE	No.2 F.O./ Gas	EPA method 9	Annually [4]		60 Minutes	No	E.8
	74.4 MW	NOx	No.2 F.O./ Gas	EPA method 20	Annually		1 hour	Yes	E.8
		SO_2	No.2 F.O. [5]	ASTM D2622-92, D4294 or both ASTM D4057 and ASTM D129-91					E.9. E.11. E.12
	Acid Rain Phase II Unit	SO_2	Natural Gas	ASTM D 1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent)					E.9. E.11. E.12
		CO	No.2 F.O./ Gas [6]	EPA method 10	Initial only		1 hour		
		SAM	No. 2 F.O.	ASTM D2622-92, D4294 or both ASTM D4057 and ASTM D129-91					E.9. E.11. E.12
		SAM	Natural Gas	ASTM D 1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent)					E.9. E.11. E.12
		PM10	No. 2 F.O.	ASTM D2622-92, D4294 or both ASTM D4057 and ASTM D129-91					E.9. E.11. E.12
		PM	Natural Gas	ASTM D 1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent)					E.9. E.11. E.12
		Water-to-fuel	No.2 F.O./ Gas	NOx -CEMS				Yes	E.14
-005	Boiler No. 2	VE	Coal/Gas/No.2 F.O	EPA method 9	Annually [3]		60 Minutes	Yes	D.11. D.13. D.14
	2,428 MMBtu/hr	VE-SB	Coal/Gas/No.2 F.O	EPA method 9	Annually [3]		60 Minutes	Yes	D.11. D.13. D.14
	295 MW Generator	PM	Coal/Gas/No.2 F.O	EPA 17, 5, 5B or 5F	Annually [3]		1 Hour	No	D.11. D.13. D.14
		PM-SB	Coal/Gas/No.2 F.O	EPA 17, 5, 5B or 5F	Annually [3]		1 Hour	No	D.11. D.13. D.14
	Acid Rain Phase II Unit	NOx	Coal/Gas/No.2 F.O	EPA 7,7A,7C,7D, 7E	Annually		1 hour	Yes	D.11. D.13. D.14
		SO_2	No.2 Fuel Oil	Fuel Sampling & Analysis As Fired				Yes	D.10
		SO_2	Coal/Gas/No.2 F.O	EPA 6,6A,6C	Annually		1 hour	Yes	D.11. D.13. D.14

[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 fuel oil is fired less than 400 hours.

[4] 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.

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

[6] Initial test only

[electronic file name: 0010006.xls]

Appendix H-1, Permit History/ID Number Changes

Gainesville Regional Utilities
Deerhaven

Facility ID No.: 0010006

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1,2]	Revised Date(s)
-001	Combustion Turbine #1	AO01-202759	12/13/91	01/01/97		
-002	Combustion Turbine #2	AO01-199846	10/02/91	10/01/96		
-003	Boiler No.1	AO01-224219	04/30/93	06/01/98		
-004	Incinerator	AO01-202758	12/13/91	01/01/97		
-005	Boiler No.2	PA74-04	05/16/78			modified 01/27/87
-006	Combustion Turbine #3, 74 MW Simply Cycle	PSD-FL-212, PA74-04D	04/07/95 04/06/95			

(if applicable) ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 31JAX01000604

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

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

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AIR REGULATION

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 Boiler ID#	b Compliance Plan Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	c Compliance Plan Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
B1	Yes	NO		
B2	Yes	NO		
CT3	Yes	NO	12/20/95	4/1/96
	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 JHancock	Date 1/9/96

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

AIRS
FINDS

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

February 23, 1994

U. S. Environmental Protection Agency
Acid Rain Program (6204J)
Attention: Designated Representative
401 M Street, SW
Washington, DC 20460

Re: Gainesville Regional Utilities
Deerhaven and J. R. Kelly
Certificate of Representation

Dear Sir or Madam:

Enclosed is one (1) original and three (3) copies of the Certificate of Representation for Gainesville Regional Utilities Deerhaven and J. R. Kelly generating stations.

If you have any questions, please call me at (904) 334-3400 ext. 1284.

Sincerely,

Yolanta E. Jonynas
Senior Environmental Engineer

YEJ:gm
Enclosures

xc: Fred Hancock
Randy Casserleigh
Larry McDaniel
CAA/DR

CORDHJRK.WI

Unite_ States
Envirc ental Protection Agency
Acid R_ Program

OMB No. 2060-0221
Expires 6-30-95

EPA

Certificate of Representation

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

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
Enter requested information for the designated representative

Name Mr. John F. Hancock, Jr.

Address
Gainesville Regional Utilities
P. O. Box 147117 (A132)
Gainesville, FL 32614-7117

Phone Number	Fax Number
904-334-3400 ext. 1712	904-334-2786

STEP 3
Enter requested information for the alternate designated representative - (optional)

Name Mr. Randy Casserleigh

Address
Gainesville Regional Utilities
P. O. Box 147117 (D38)
Gainesville, FL 32614-7117

Phone Number	Fax Number
904-334-2660	904-334-2672

STEP 4
Complete Step 5, read the certifications and sign and date

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

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

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

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

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

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

I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operat of the affected source and of each affected unit at the source; and

Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowanc contract, that allowances and the proceeds of transactions involving allowances will be deemed to be or distributed in accordance with the contract.

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

DEERHAVEN (GENERATING STATION)
Plant Name (from Step 1)

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.

Signature (designated representative) [signature]	Date 2/21/94
Signature (alternate) [signature]	Date 2/21/94

STEP 5
Provide the name of every owner and operator of the source and each affected unit at the source. Identify the units they own and/or operate by boiler ID# from NADB. For owners only, identify each state or local utility regulatory authority with jurisdiction over each owner

Name City of Gainesville Gainesville Regional Utilities					[X] Owner	[X] Operator
ID# B1	ID# B2	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities Florida Public Service Commission (limited authority); City Commission of the City of Gainesville						

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

Via Airborne Express

October 9, 1995

U. S. Environmental Protection Agency
Acid Rain Program (6204J)
Attention: Designated Representative
401 M Street, SW
Washington, DC 20460

RE: Gainesville Regional Utilities (Utility Code: 6909)
Deerhaven (ORIS Code: 663)

Dear Sir or Madam:

Gainesville Regional Utilities is currently completing construction of a new simple cycle combustion turbine (designated as "CT3") at the Deerhaven plant. GRU expects to initiate operation of this new unit in November 1995 and soon will be submitting Monitoring Plans for the unit's Continuous Emission Monitoring System. Therefore, notice is hereby provided that Mssrs. John F. Hancock and Randy Casserleigh are the Designated Representative and Alternate Designated Representative, respectively, for CT3. The Certificate of Representation for the Deerhaven plant was filed with the EPA by letter dated February 23, 1994.

It should be noted that the National Allowance Database Version 2.1 ("NADB") currently does not reference "CT3." It does, however, include a planned unit designated as "**NA1" at the Deerhaven plant. GRU will be filing a request with Ms. Kathy Barylski (EPA) to have unit "**NA1" redesignated as "CT3" in the NADB.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: R. Casserleigh
F. Hancock
CAA/DR

cordhct3.y17

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			0.00032	0.00032	0.0004
Hg			0.0009	0.0009	0.1
Pb			0.05746	0.05746	0.6
As			0.004854	0.004854	Any

* with power augmentation

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

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

March 25, 1994

BACT Determination Requested by the Applicant

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

BACT Determination Procedure

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

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

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

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

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

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

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

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

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

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

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

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

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

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

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

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

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

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

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

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

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

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using a low-NO_X combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_X emissions by approximately 80%, about 58.22 tons of NO_X would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.[illegible], the incremental cost effectiveness ($/ton) of controlling NO_X is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

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

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

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

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

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

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

Particulate Matter (PM) Emissions

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

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

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

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

SO_2 and H_2SO_4 Mist Control

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

PM_{10} Control

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

BACT Standards

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

MAXIMUM ALLOWABLE EMISSION LIMITS

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

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

Monitoring

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

Details of the Analysis May be Obtained by Contacting:

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Recommended by:

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

March 29, 1995
Date

Approved by:

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

April 11th, 1995
Date