



Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

P.E. Certification Statement

City of Vero Beach
Municipal Utilities

DRAFT Permit No.: 0610029-002-AV
Facility ID No.: 0610029

Project type: Initial Title V Air Operation Permit

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, 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).

This review was conducted by myself and Susan C. DeVore under my responsible supervision.



[Handwritten Signature]

7/11/97
Date

Permitting Authority:

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: 904/488-1344
Fax: 904/922-6979



Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 16, 1997

Mr. Rex Taylor
City Manager, Utilities Director
City of Vero Beach
PO Box 1389
Vero Beach, FL 32961-1389

Re: DRAFT Title V Permit No.: 0610029-002-AV
City of Vero Beach Municipal Utilities

Dear Mr. Taylor:

One copy of the DRAFT Title V Air Operation Permit for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River 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 within 30 (thirty) days of receipt of this letter. 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 Susan DeVore at 904/488-1344.

Sincerely,

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

CHF/sd

enclosures

our RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

3. Article Addressed to:
 Mr. Shuler W. Massey
 Director of Power Resources
 City of Vero Beach
 P. O. Box 1389
 100 17th Street
 Vero Beach, Florida 32961-1389

5. Signature (Addressee)
 [Signature]

6. Signature (Agent)
 [Signature]

4a. Article Number
 2 127 635 505

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

7. Date of Delivery
 7-21-97

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

1. Addressee's Address fee)
 2. Restricted Delivery Consult postmaster for fee.

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

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, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
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 City Manager, Utilities Director
 City of Vero Beach
 P. O. Box 1389
 100 17th Street
 Vero Beach, Florida 32961-1389

5. Signature (Addressee)
 [Signature]

6. Signature (Agent)
 [Signature]

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1. Addressee's Address fee)
 2. Restricted Delivery Consult postmaster for fee.

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

Thank you for using Return Receipt Service.

2 127 635 505



Receipt for Certified Mail

No Insurance Coverage Provided
 Do not use for International Mail
 (See Reverse)

Sent to Mr. Shuler W. Massey	
Street and No. P. O. Box 1389	
P.O., State and ZIP Code Vero Beach, FL 32961-1389	
Postage	\$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	\$
Postmark or Date 07/17/97	
Facility ID#: 0610029-002-AV City of Vero Beach	

1993 March 0983 U.S.P.S.

2 127 635 504



Receipt for Certified Mail

No Insurance Coverage Provided
 Do not use for International Mail
 (See Reverse)

Sent to Mr. Rex Taylor	
Street and No. P. O. Box 1389	
P.O., State and ZIP Code Vero Beach, FL 32961-1389	
Postage	\$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	\$
Postmark or Date 07/17/97	
Facility ID#: 0610029-002-AV City of Vero Beach	

1993 March 0983 U.S.P.S.

In the Matter of an
Application for Permit by:

City of Vero Beach
1053 20th Place
Vero Beach, FL 32961-1389

DRAFT Permit No.: 0610029-002-AV
City of Vero Beach Municipal Utilities
Indian River 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 Vero Beach, applied on June 14, 1997, to the permitting authority for a Title V air operation permit for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River 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 within 30 (thirty) days 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: 904/488-1344; Fax: 904/922-6979), 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., or a party requests mediation as an alternative remedy under Section 120.573, F.S., before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the 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 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 (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, 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.

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

A request for mediation must contain the following information:

- (a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any;
- (b) A statement of the preliminary agency action;
- (c) A statement of the relief sought; and,
- (d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following:

- (a) The names, addresses, and telephone numbers of any persons who may attend the mediation;
- (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;
- (c) The agreed allocation of the costs and fees associated with the mediation;
- (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;
- (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;
- (f) The name of each party's representative who shall have authority to settle or recommend settlement; and,
- (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573, F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, F.S., for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within 60 (sixty) days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department of Environmental Protection must enter an order incorporating the agreement of the parties in accordance with the provisions of Section 403.0872(7), F.S. If mediation terminates without settlement of the dispute, the permitting authority shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, F.S., remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply 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 410 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 7/17/97 to the person(s) listed:

Mr. Rex Taylor, City Manager, Utilities Director
Mr. Shuler W. Massey, Director of Power Resources

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, unless otherwise indicated, on the same date to the person(s) listed:

Mr. Kennard Kosky, P.E., Golder Associates
Mr. Richard M. Siefert, City of Vero Beach Power Plant
Mr. Len Kozlov P.E., DEP Central District
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)

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 7/17/97
(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.: 0610029-002-AV
City of Vero Beach Municipal Utilities
Indian River County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V air operation permit to City of Vero Beach for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River County. A case-by-case Maximum Achievable Control Technology (MACT) determination was not required in this permitting action. The applicant's name and address are: City of Vero Beach, Rex Taylor, City Manager, Utilities Director, City of Vero Beach, 1053 20th Place, PO Box 1389, Vero Beach, FL 32961-1389.

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 unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statutes (F.S.), or a party requests mediation as an alternative remedy under Section 120.573, F.S., before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the 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 (or a request for mediation, as discussed below) 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,

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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.

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

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(c) A statement of the relief sought; and,

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

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

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

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

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dispute, the Department of Environmental Protection must enter an order incorporating the agreement of the parties in accordance with the provisions of Section 403.0872(7), F.S. If mediation terminates without settlement of the dispute, the permitting authority shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, F.S., remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, 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 410 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:

Permitting Authority:

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

Affected District/Local Program:

Central District
3319 Maguire Boulevard, Suite 232, Orlando, FL 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

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 904/488-1344, for additional information.

City of Vero Beach
City of Vero Beach Municipal Utilities
Facility ID No.: 0610029
Indian River County

Initial Title V Air Operation Permit
DRAFT Permit No.: 0610029-002-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: 904/488-1344
Fax: 904/922-6979

Drafted on July 15, 1997

Initial Title V Air Operation Permit
DRAFT Permit No.: 0610029-002-AV

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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 Vero Beach
PO Box 1389
Vero Beach, FL 32961-1389

DRAFT Permit No.: 0610029-002-AV

Facility ID No.: 0610029

SIC Nos.: 49, 4931

Project: Initial Title V Air Operation Permit

This permit is for the operation of the City of Vero Beach Municipal Utilities. This facility is located at 100 17th Street, Vero Beach, Indian River County; UTM Coordinates: Zone 17, 561.4 km East and 3056.5 km North; Latitude: 27° 37' 52" North and Longitude: 80° 22' 33" 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

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

Table 2-1, Summary of Compliance Requirements

Appendix TV-1, Title V Conditions (version dated 2/27/97)

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)

Phase II Acid Rain Application/Compliance Plan received 07/01/95

Alternate Sampling Procedure: ASP Number 97-B-01

BACT Determination dated June 28, 1991

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/sms/sd

Section I. Facility Information.

Subsection A. Facility Description.

This facility is an electric power generating plant located adjacent to a wastewater treatment facility and consists of:

Fossil Fuel Steam Generating Unit 1 (Emissions Unit 001), rated at 13 MW;

Fossil Fuel Steam Generating Unit 2 (Emissions Unit 002), rated at 17 MW;

Fossil Fuel Steam Generating Unit 3 (Emissions Unit 003), rated at 34 MW;

Fossil Fuel Steam Generating Unit 4 (Emissions Unit 004), rated at 56 MW;

Combined Cycle Gas Turbine Unit 5 (Emissions Unit 005), rated at 38 MW.

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 ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

Unregulated Emissions Units and/or Activities, See Appendix U-1	
006	Fuel oil, gasoline and lube oil storage tanks.
007	Waste water treatment plant.

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:
 Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
 Appendix H-1, Permit History/ID Number Changes
 Table 1-1, Summary of Air Pollutant Standards and Terms
 Table 2-1, Summary of Compliance Requirements

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 (version dated 2/27/97), 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.** The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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

4. **Prevention of Accidental Releases (Section 112(r) of CAA).** 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 (VOC) Emissions or Organic Solvents (OS) Emissions.** The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.

- d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.]

8. Not Federally Enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- a. Maintenance of paved areas as needed.
- b. Regular mowing of grass and care of vegetation.
- c. Limiting access to plant property by unnecessary vehicles.
- d. Care in handling and use of bagged chemical products.

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

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1961.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	202	Natural Gas
	140	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

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

A.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil. Number 2 fuel oil may be used as an ignitor fuel.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

A.4. 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.
[Rule 62-296.406(1), F.A.C.]

A.5. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

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

[Rule 62-210.700(3), F.A.C.]

A.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content fuel oil. See specific condition **A.7.**
[Rule 62-296.406(2), F.A.C., BACT Determination 2/14/91]

A.7. Sulfur Dioxide - Sulfur Content. The fuel oil sulfur content shall not exceed 1.5 percent, by weight.
[Rule 62-296.406(3), F.A.C., BACT Determination 2/14/91]

Test Methods and Procedures

A.8. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery.
[Rules 62-213.440 and 62-296.406(3), F.A.C.]

A.9. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91.
[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.]

Monitoring of Operations

A.10. Annual Tests Required - VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

A.11. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

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

E.U. ID No.	Brief Description
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1961.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	248	Natural Gas
-----	243	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **F.14.**

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

B.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil.

[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

B.4. 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.

[Rule 62-296.406(1), F.A.C.]

B.5. 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.]

B.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content fuel oil. See specific condition **B.7.**

[Rules 62-4.070(3) and 62-296.406(2), F.A.C., BACT for this source will be the same as that of the BACT Determination of 2/14/91 for EU 001]

B.7. Sulfur Dioxide - Sulfur Content. The fuel oil sulfur content shall not exceed 1.5 percent, by weight.

[Rules 62-4.070(3) and 62-296.406(3), F.A.C., BACT for this source will be the same as that of the BACT Determination of 2/14/91 for EU 001]

Test Methods and Procedures

B.8. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery.

[Rules 62-213.440 and 62-296.406(3), F.A.C.]

B.9. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91.

[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.]

Monitoring of Operations

B.10. Annual Tests Required - VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

B.11. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

Subsection C. This section addresses the following emissions unit.

003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
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{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 3 began commercial operation in 1971.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
003	417	Natural Gas
	410	Fuel Oil

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

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

C.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

C.4. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(a), F.A.C.]

C.5. 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 3 has an operational continuous opacity monitor.]

C.6. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

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

C.8. 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.j., F.A.C.]

Test Methods and Procedures

C.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.]

C.10. Sulfur Dioxide. **The permittee elected to demonstrate compliance with the sulfur dioxide limitation 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 **C.11** and **C.12**.
[Rule 62-296.405(1)(f)1.b., F.A.C.]

C.11. 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 **C.12**.
[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]

C.12. The following fuel sampling and analysis program 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, or both ASTM D4057-88 and ASTM D129-91 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, 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 SO₂ 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.]

Monitoring of Operations

C.13. Annual Tests Required - PM and VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for particulate matter emissions and visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

C.14. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

Subsection D. This section addresses the following emissions unit.

004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200-ft. stack.
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{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. The affected facility to which this subpart applies is fossil fuel steam generator, Unit 4, emissions unit 004. Fossil fuel fired steam generator Unit 4 began commercial operation in 1976.}

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:

Unit No.	mmBtu/hr Heat Input	Fuel Type
004	685	Natural Gas
	685	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE)]

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 any combination of natural gas and numbers 4 or 6 fuel oil, except that firing of number 6 fuel oil is limited to no more than 32% of the total heat input to the boiler at any given time.
[Rule 62-213.410, F.A.C., AO 31-229058, 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 4 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.

(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.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 NO₂ in excess of:

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

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel

(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:

$$PS_{NO_x} = (86x + 130y) / (x + y)$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired;

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.

[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 SO₂ 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 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 SO₂ 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, SO₂, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

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

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

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

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

% O₂ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

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

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

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

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

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

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

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

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

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

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

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

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

(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) (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, SO₂ and NO_X may be determined by using the F_c factor, provided that the following procedure is used:

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

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

where:

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

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

%CO₂ = carbon dioxide concentration, percent dry basis.

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

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

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

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

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

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

(3) Particulate matter and SO₂ 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 SO₂ (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 SO₂ 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 O₂ concentration (%O₂) 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, SO₂ and NO_x. 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. Testing, if required, shall be conducted while burning number 6 fuel oil at a heat input of 32% of the total heat input to the boiler.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

D.14. Pursuant to 40 CFR 60.45 Emission and Fuel Monitoring.

CMS for Opacity Required, for NO_x and SO₂ Not Required.

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

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d).

(3) Notwithstanding 40 CFR 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under 40 CFR 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in 40 CFR 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required.

[40 CFR 60.45(a) & (b)]

Excess Emission Reports.

(g) Excess emission 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 report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions that shall be reported are defined as follows:

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

[40 CFR 60.45(g)]

Other NSPS Subpart D Conditions

D.15. 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.

Common Conditions

D.16. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

D.17. These emissions units are also subject to conditions **G.1** through **G.6** contained in **Subsection G. NSPS Common Conditions.**

Subsection E. This section addresses the following emissions unit.

005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.
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{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 combined cycle gas turbine, Unit 5. This unit underwent a BACT Determination dated June 28, 1991. BACT Limits were incorporated into the subsequent PSD permits including AC 31-253502 (PSD-FL-152B). Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 125 ft. stack. Emissions are controlled by dry low-NOx combustors, and by water injection when firing fuel oil. The turbine exhaust may also be vented through a bypass stack for simple cycle operation. The turbine began commercial operation in 1992.}

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:

Unit No.	mmBtu/hr Heat Input	Fuel Type
005	414*	Natural Gas
	455*	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.
 [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., and AC 31-253502 (PSD-FL-152B)]

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

E.3. Methods of Operation - Fuels. Any combination of only natural gas and number 2 fuel oil shall be fired in the combustion turbine.
 {Note: The limitations of specific conditions **E.3** and **E.6** 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. The permitted fuel oil utilization rates for this emissions unit are:

- a. Maximum consumption of number 2 fuel oil shall not exceed 3,482 gal./hr.
- b. Maximum annual consumption of number 2 fuel oil shall not exceed 10,000,000 gal./yr.
- c. Maximum annual firing using number 2 fuel oil shall not exceed 33% of the annual capacity factor.

[Rules 62-4.070(3) and 62-213.440, F.A.C., and AC 31-253502 (PSD-FL-152B)]

Emission Limitations and Standards

E.5. Visible Emissions Visible emissions shall not exceed 10% opacity.
 [AC 31-253502 (PSD-FL-152B)]

E.6. Sulfur Dioxide - Sulfur Content. The No. 2 fuel oil sulfur content shall not exceed 0.25 percent, by weight. See specific conditions **E.12 and E.13**. The natural gas sulfur content shall not exceed 10 grains per hundred cubic feet (standard conditions). See specific condition **E.17**. {Note: The limitations of specific conditions **E.3 and E.6** are 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., and AC 31-253502 (PSD-FL-152B)]

E.7. The maximum allowable emissions from Unit 5 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Tons/Year ^{a, b}	
NOx ^c	25 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	243.7	BACT
SO2	Natural gas as fuel	0.25% S by weight	178.2	BACT
PM	0.006 lb/mmBtu	0.025 lb/mmBtu	23.7	BACT
VOC	0.0112 lb/mmBtu	0.0113 lb/mmBtu	21.0	BACT
CO	0.0224 lb/mmBtu	0.0226 lb/mmBtu	42.1	BACT

- a Tons per year based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing.
- b Based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.
- c NOx emission limit during co-firing of natural gas and number 2 fuel oil shall be determined by the following:

$$\text{NOx Limit} = \frac{(\text{Lg} \times \text{Qg}) + (\text{Lo} \times \text{Qo})}{\text{Qg} + \text{Qo}}$$

where:

- Lg = Emission limit for natural gas
- Qg = Heat input of natural gas
- Lo = Emission limit for fuel oil
- Qo = Heat input of fuel oil

{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.}
 [AC 31-253502 (PSD-FL-152B) 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 through F.8 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., and AC 31-253502 (PSD-FL-152B)]

E.9. Testing for PM, CO, VOC. Except as provided in specific conditions F.6 through F.8 of this permit, emission testing for emissions of particulate matter and carbon monoxide shall be performed in the year prior to renewal of this permit, in accordance with specific condition E.10, while burning fuel oil. Emission testing for emissions of VOC shall be performed only if the CO test does not demonstrate compliance with the emissions limitation of specific condition E.7 of this permit. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests, if required, shall be conducted using EPA test method 25A.

[Rules 62-4.070(3) and 62-213.440, F.A.C., and AC 31-253502 (PSD-FL-152B)]

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. 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. 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.

[AC 31-253502 (PSD-FL-152B)]

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 D129-91 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.

[Rule 62-213.440, F.A.C., and , and AC 31-253502 (PSD-FL-152B)]

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.

[AC 31-253502 (PSD-FL-152B) and requested by applicant in the initial Title V permit application received June 27, 1996]

E.14. Excess Emissions by CEMS. The CEMS for NO_x shall be used to determine periods of excess emissions. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **E.7** of this permit. Periods of startup, shutdown, malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

{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) and 62-213.440, F.A.C.]

Record Keeping and Reporting Requirements

E.15. Natural Gas Sulfur Content Records Required. 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. Additional Reports Required. 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., and, AC 31-253502 (PSD-FL-152B)]

Other Conditions

E.17. Maintain SCR Duct Work. The permittee shall maintain duct work suitable for future installation of a selective catalytic reduction (SCR) system. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT. If an SCR system is installed, it may be bypassed during simple cycle operation.
[AC 31-253502 (PSD-FL-152B)]

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.**

Subsection F. Common Conditions.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

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

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

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.]

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.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62-210.300(4), F.A.C.

(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 shall 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.]

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. When VE Tests Not Required. 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 62-4.070(3), 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.}

F.9. Visible Emissions - Boiler 4, Turbine. The test method for visible emissions for emissions units 004 (Unit 4) and 005 (Turbine, Unit 5) 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 1, 2 and 3. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2) and 003 (Unit 3) 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 Central 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 Central District Air Section.
[Rule 62-210.700(6), F.A.C.]

F.18. Excess Emissions - Report. Submit to the Central 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., and AC 31-253502 (PSD-FL-152B)]

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 Central District Air Section on the results of each such test.
- (b) The required test report shall be filed with the Central 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 Central 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. NSPS Common Conditions.

<u>E.U. ID</u> <u>No.</u>	<u>Brief Description</u>
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

{Note: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected facilities to which this subpart applies are fossil fuel steam generator, Unit 4 and the combined cycle gas turbine, Unit 5.}

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 five years following the date of such measurements, maintenance, reports, and records.

[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

G.2. Pursuant to 40 CFR 60.8 Performance Tests.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining

compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

G.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

- (a) Compliance with standards in this part, other than opacity standards, shall be determined only by 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 IV. This section is the Acid Rain Part.

Operated by: City of Vero Beach
ORIS code: 0693

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

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

E.U. ID No.	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4
005	Combined Cycle Gas Turbine, Unit 5

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is 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 12/27/95.
 [Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO₂) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit is as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002
003	3	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	312*	312*	312*
		NOx limit	**	**	**
004	4	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	106*	106*	106*
		NOx limit	**	**	**
005	5	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	314*	314*	314*
		NOx limit	**	**	**

* 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. Comments, notes, and justifications: None.

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

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

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

E.U. ID

No.

Brief Description of Emissions Units and/or Activity

- | | |
|-----|--|
| 006 | Fuel oil, gasoline and lube oil storage tanks. Tanks are:
Tank 1 (1,560,000 gal. capacity) fuel oil;
Tank 2 (3,108,000 gal. capacity) fuel oil;
Tank 3 (350,000 gal. capacity) fuel oil;
Diesel fuel tank for vehicles (500 gal. capacity);
Gasoline fuel tank for vehicles (500 gal. capacity);
Diesel tank for Unit 5 startup generator;
Four lube oil tanks, one each for Units 1 - 4. |
| 007 | Waste water treatment plant, including headworks, liquid treatment processes and storage tanks. |

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

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. Startup generator diesel engine associated with Unit 5.
2. Solvent use and hoods for laboratory.
3. Vapor extractor rooftop vents, one each for Units 1-4.
4. Cooling tower.

**Appendix S
 Permit Summary Tables**

Table 1-1, Summary of Air Pollutant Emission Standards

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 40% for 2 min. each hour					Rule 62-296.406(1), F.A.C.	A.4, B.4
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60% opacity					Rule 62-210.700(3), F.A.C.	A.5, B.5
PM, SO ₂ Unit 1	Oil	8760	1.5% S by weight, fuel oil			230.2*	1008*	Rules 62-4.070(3) & 62-296.406(2), F.A.C., & BACT	A.6 & A.7, B.6 & B.7
PM, SO ₂ Unit 2	Oil	8760	1.5% S by weight, fuel oil			399.5*	1750*	Rules 62-4.070(3) & 62-296.406(2), F.A.C., & BACT	A.6 & A.7, B.6 & B.7

Notes for EU 001 & 002:

* Lb/hour and TPY values are for SO₂ emissions using fuel oil.

Appendix S
 Permit Summary Tables

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 40% for 2 min. each hour					Rule 62-296.405(1)(a), F.A.C.	C.4
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods)					Rule 62-210.700(3), F.A.C.	C.5
PM Steady State	Oil, Natural Gas	8760	0.1 lb/mmBtu			41*	179.6*	Rule 62-296.405(1)(b), F.A.C.	C.6
PM Soot Blowing or Load Change	Oil, Natural Gas	8760	0.3 lb/mmBtu			123*	67.3*	Rule 62-210.700(3), F.A.C.	C.7
SO ₂	Oil, Natural Gas	8760	2.75 lb/mmBtu			1127.5**	4938**	Rules 62-213.440, & 62-296.405(1)(c)1.j. F.A.C.	C.8

Notes for EU 003:

* Lb/hour and TPY values are for PM emissions using fuel oil.

** Lb/hour and TPY values are for SO₂ emissions using fuel oil.

Appendix S
Permit Summary Tables

Emissions Unit	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions ^a			Equivalent Emissions ¹		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 27% for 6 min. each hour					40 CFR 60.42(a)(2)	D.6
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods)					Rule 62-210.700(3), F.A.C.	D.4
PM Steady State	Oil, Natural Gas	8760	0.1 lb/mmBtu			68.5*	300*	40 CFR 60.42(a)(1)	D.6
PM Soot Blowing or Load Change	Oil, Natural Gas	8760	0.3 lb/mmBtu			205.5*	112.5*	Rule 62-210.700(3), F.A.C.	D.5
SO ₂	Oil, Natural Gas	8760	0.80 lb/mmBtu			548	2400	40 CFR 60.43(a)(1)	D.7
NO _x	Natural Gas	8760	0.20 lb/mmBtu			137	600.1	40 CFR 60.44(a)(1)	D.8
NO _x	Oil	8760	0.30 lb/mmBtu			205.5*	900.1*	40 CFR 60.44(a)(2)	D.8

Notes for EU 004:

* Lb/hour and TPY values for PM and NO_x emissions based on using number 4 fuel oil for total heat input.

a Firing of number 6 fuel oil is limited to no more than 32% of the total heat input to the boiler at any given time.

Appendix S
 Permit Summary Tables

Emissions Unit	Brief Description
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY ^a	lb/hour ^b	TPY ^b		
VE	No. 2 Fuel Oil, Natural Gas	8760	10 % opacity					AC 31-253502 (PSD-FL-152B)	E.5
SO ₂	"	8760	0.25% S by weight, fuel oil 10 gr S/ccf, natural gas		178.2	123		AC 31-253502 (PSD-FL-152B)	E.6
NO _x	No. 2 Fuel Oil	8760	42 ppmvd at 15% oxygen on a dry basis		243.7	79	114.2	AC 31-253502 (PSD-FL-152B)	E.7
NO _x	Natural Gas	8760	25 ppmvd at 15% oxygen on a dry basis		243.7	44.3	194	AC 31-253502 (PSD-FL-152B)	E.7
PM	No. 2 Fuel Oil	8760	0.025 lb/mmBtu		23.7	11.4	16.4	AC 31-253502 (PSD-FL-152B)	E.7
PM	Natural Gas	8760	0.006 lb/mmBtu		23.7	2.5	10.9	AC 31-253502 (PSD-FL-152B)	E.7
VOC	No. 2 Fuel Oil	8760	0.0113 lb/mmBtu		21.0	5.1	7.4	AC 31-253502 (PSD-FL-152B)	E.7
VOC	Natural Gas	8760	0.0112 lb/mmBtu		21.0	4.6	20.3	AC 31-253502 (PSD-FL-152B)	E.7
CO	No. 2 Fuel Oil	8760	0.0226 lb/mmBtu		42.1	10.3	14.9	AC 31-253502 (PSD-FL-152B)	E.7
CO	Natural Gas	8760	0.0224 lb/mmBtu		42.1	9.3	40.6	AC 31-253502 (PSD-FL-152B)	E.7

Appendix S
Permit Summary Tables

Notes for EU 005:

- a Tons per year based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing, based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.
- b Equivalent emissions based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing, based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.

Notes:

¹ The "Equivalent Emissions" listed are for informational purposes only. [Rule 62-213.205, F.A.C.]

NA = not applicable

**Appendix S
 Permit Summary Tables**

Table 2-1, Summary of Compliance Requirements

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	DEP Method 9	Annual	August 1st	1 hour	No	A.10, B.10
PM, SO ₂	Oil	Fuel Sampling & Analysis	As Fired			No	A.8 & A.9, B.8 & B.9

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	DEP Method 9	Annual	August 1st	1 hour	No	C.13
PM	"	EPA Test Methods 17, 5, 5B, or 5F	Annual	August 1st	3 hours	No	C.9, C.13
SO ₂	"	Fuel Sampling & Analysis	As Fired			No	C.10, C.11, C.12

**Appendix S
 Permit Summary Tables**

Emissions Unit	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	EPA Method 9	Annual	August 1st	1 hour	No	D.9, D.12
PM	"	EPA Test Methods 5, 5B, or 17	Annual	August 1st	3 hours	No	D.6, D.9, D.12
SO₂	"	Fuel Sampling & Analysis	As Fired			No	D.7, D.12
NO_x	"	EPA Test Methods 7, 7A, 7C, 7D, or 7E	Annual	August 1st	3 hours	No	D.9, D.12

**Appendix S
 Permit Summary Tables**

Emissions Unit	Brief Description
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	No 2 Fuel Oil, Natural Gas	EPA Method 9	Annual	August 1st	1 hour	No	E.8
SO₂	"	Fuel Sampling & Analysis	As Fired			Yes*	E.6, E.12, E.17.
NO_x	No 2 Fuel Oil, Natural Gas	EPA Test Method 20	Annual	August 1st	3 hours	Yes	E.8
PM	"	EPA Test Methods 5 or 17	Prior to Renewal		3 hours	No	E.9
VOC	"	EPA Test Method 10	Only if CO test fails			No	E.9
CO	"	EPA Test Method 25A	Prior to Renewal			No	E.9

Notes for EU 005:

* Continuous monitoring of fuel consumption required.

Notes:

¹ Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

² CMS = continuous monitoring system

See also Section F for general testing requirements.

APPENDIX TV-1, TITLE V CONDITIONS (version dated 02/27/97)

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

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

Chapter 62-4, F.A.C.

1. General Prohibition. Any stationary installation which will reasonably be expected to be a source of pollution shall not be operated, maintained, or modified without the appropriate and valid permits issued by the Department, unless the source is exempted by Department rule. The Department may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit.

[Rule 62-4.030, Florida Administrative Code (F.A.C.); Section 403.087, Florida Statute (F.S.)]

2. Not federally enforceable. Procedure to Obtain Permits: Application.

(1) Any person desiring to obtain a permit from the Department shall apply on forms prescribed by the Department and shall submit such additional information as the Department by law may require.

(2) All applications and supporting documents shall be filed in quadruplicate with the Department.

(3) To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. All applications for a Department permit shall be certified by a professional engineer registered in the State of Florida except when the application is for renewal of an air pollution operation permit at a minor facility as defined in Rule 62-210.200, F.A.C., or where professional engineering is not required by Chapter 471, F.S. Where required by Chapter 471 or 492, F.S., applicable portions of permit applications and supporting documents which are submitted to the Department for public record shall be signed and sealed by the professional(s) who prepared or approved them.

(4) Processing fees for air construction permits shall be in accordance with Rule 62-4.050(4), F.A.C.

(5)(a) To be considered by the Department, each application must be accompanied by the proper processing fee. The fee shall be paid by check, payable to the Department of Environmental Protection. The fee is non-refundable except as provided in Section 120.60, F.S., and in this section.

(c) Upon receipt of the proper application fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin.

(d) If the applicant does not submit the required fee within ten days of receipt of written notification, the Department shall either return the unprocessed application or arrange with the applicant for the pick up of the application.

(e) If an applicant submits an application fee in excess of the required fee, the permit processing time requirements of Sections 120.60(2) and 403.0876, F.S., shall begin upon receipt, and the Department shall refund to the applicant the amount received in excess of the required fee.

(6) Any substantial modification to a complete application shall require an additional processing fee determined pursuant to the schedule set forth in Rule 62-4.050, F.A.C., and shall restart the time requirements of Sections 120.60 and 403.0876, F.S. For purposes of this Subsection, the term "substantial modification" shall mean a modification which is reasonably expected to lead to substantially different environmental impacts which require a detailed review.

(7) Modifications to existing permits proposed by the permittee which require substantial changes in the existing permit or require substantial evaluation by the Department of potential impacts of the proposed modifications shall require the same fee as a new application.

[Rule 62-4.050, F.A.C.]

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

[Rule 62-4.070(7), F.A.C.]

4. Modification of Permit Conditions.

(1) For good cause and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions and on application of the permittee the Department may grant additional time. For the purpose of this section, good cause shall include, but not be limited to, any of the following:

- (a) A showing that an improvement in effluent or emission quality or quantity can be accomplished because of technological advances without unreasonable hardship.
- (b) A showing that a higher degree of treatment is necessary to effect the intent and purpose of Chapter 403, F.S.
- (c) A showing of any change in the environment or surrounding conditions that requires a modification to conform to applicable air or water quality standards.
- (e) Adoption or revision of Florida Statutes, rules, or standards which require the modification of a permit condition for compliance.

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

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

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

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

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

6. Suspension and Revocation.

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

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

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

- (a) Submitted false or inaccurate information in application or operational reports.
- (b) Has violated law, Department orders, rules or permit conditions.
- (c) Has failed to submit operational reports or other information required by Department rules.
- (d) Has refused lawful inspection under Section 403.091, F.S.

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

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

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

APPENDIX TV-1, TITLE V CONDITIONS (version dated 02/27/97) (continued)

8. Transfer of Permits.

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

9. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.
- [Rule 62-4.130, F.A.C.]

10. For purposes of notification to the Department pursuant to Rule 62-4.130, F.A.C., Plant Operation-Problems, "immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays.
- [40 CFR 70.6(a)(3)(iii)(B)]

11. Review. Failure to request a hearing within 14 days of receipt of notice of proposed or final agency action on a permit application or as otherwise required in Chapter 62-103, F.A.C., shall be deemed a waiver of the right to an administrative hearing.
- [Rule 62-4.150, F.A.C.]

12. Permit Conditions. All permits issued by the Department shall include the following general conditions:

- (1) The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
- (2) This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
- (3) As provided in subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit.
- (4) This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

APPENDIX TV-1, TITLE V CONDITIONS (version dated 02/27/97) (continued)

- (5) This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department.
- (6) The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
- (7) The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:
- (a) Have access to and copy any records that must be kept under conditions of the permit;
 - (b) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,
 - (c) Sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.
- (8) If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
- (a) A description of and cause of noncompliance; and,
 - (b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.
- (9) In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the F.S. or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
- (10) The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
- (11) This permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
- (12) This permit or a copy thereof shall be kept at the work site of the permitted activity.
- (14) The permittee shall comply with the following:
- (a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - (b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - (c) Records of monitoring information shall include:
 - 1. the date, exact place, and time of sampling or measurements;
 - 2. the person responsible for performing the sampling or measurements;
 - 3. the dates analyses were performed;
 - 4. the person responsible for performing the analyses;
 - 5. the analytical techniques or methods used; and,
 - 6. the results of such analyses.
- (15) When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.
- [Rules 62-4.160 and 62-213.440(1)(b), F.A.C.]

13. Construction Permits.

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

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

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

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

(2) The construction permit may contain conditions and an expiration date as determined by the Secretary or the Secretary's designee.

(3) When the Department issues a permit to construct, the permittee shall be allowed a period of time, specified in the permit, to construct, and to operate and test to determine compliance with Chapter 403, F.S., and the rules of the Department and, where applicable, to apply for and receive an operation permit. The Department may require tests and evaluations of the treatment facilities by the permittee at his/her expense.

[Rule 62-4.210, F.A.C.]

14. Operation Permit for New Sources. To properly apply for an operation permit for new sources, the applicant shall submit certification that construction was completed noting any deviations from the conditions in the construction permit and test results where appropriate.

[Rule 62-4.220, F.A.C.]

Chapter 62-103, F.A.C.

15. Public Notice, Public Participation, and Proposed Agency Action. The permittee shall comply with all of the requirements for public notice, public participation, and proposed agency action pursuant to Rule 62-103.150 and Rule 62-210.350, F.A.C.

[Rules 62-103.150, 62-210.350 and 62-213.430(1)(b), F.A.C.]

16. Administrative Hearing. The permittee shall comply with all of the requirements for a petition for administrative hearing or waiver of right to administrative proceeding pursuant to Rule 61-103.155, F.A.C.

[Rule 62-103.155, F.A.C.]

Chapter 62-204, F.A.C.

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

[40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

Chapter 62-210. F.A.C.

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

(1) Air Construction Permits. An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification, in accordance with all applicable provisions of Chapters 62-210, 62-212 and 62-4, F.A.C. The construction permit shall be issued for a period of time sufficient to allow construction or modification of the facility or emissions unit and operation while the new or modified facility or emissions unit is conducting tests or otherwise demonstrating initial compliance with the conditions of the construction permit.

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

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

1. Specify the manner, nature, volume and frequency of the emissions permitted, and the applicable emission limiting standards or performance standards, if any;
2. Require proper operation and maintenance of any pollution control equipment by qualified personnel, where applicable in accordance with the provisions of any operation and maintenance plan required by the air pollution rules of the Department.
3. Contain an effective date stated in the permit which shall not be earlier than the date final action is taken on the application and be issued for a period, beginning on the effective date, as provided below.

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

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

- (i) the owner or operator of the emissions unit demonstrates to the Department that the emissions unit may need to be reactivated and used, or that it is the owner's or operator's intent to apply to the Department for a permit to construct a new emissions unit at the facility before the end of the extension period; and,
- (ii) the owner or operator of the emissions unit agrees to and is legally prohibited from providing the allowable emission permitted by the renewed permit as an emissions offset to any other person under Rule 62-212.500, F.A.C.; and,
- (iii) the emissions unit was operating in compliance with all applicable rules as of the time the source was shut down.

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

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

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

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

19. Notification of Startup. The owner or operator of any emissions unit or facility which has a valid air operation permit and which has been shut down more than one (1) year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of sixty (60) days prior to the intended startup date.

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

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

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

20. Emissions Unit Reclassification.

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

(b) If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

21. Public Notice and Comment.

(1) Public Notice of Proposed Agency Action.

(a) Notwithstanding any discretionary public notice requirements contained in Rule 62-103.150(2)(a), F.A.C., a notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant for:

1. A construction permit for any proposed new or modified facility or emissions unit;
2. An operation permit, permit renewal or permit revision subject to Rule 62-210.300(2)(b), F.A.C.; or
3. An operation permit, permit renewal, or permit revision subject to Chapter 62-213, F.A.C., except those permit revisions meeting the requirements of Rule 62-213.412(1), F.A.C.

(b) The notice required by Rule 62-210.350(1)(a), F.A.C., shall be published in accordance with all otherwise applicable provisions of Rule 62-103.150, F.A.C.

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

(a) Before taking final agency action on a construction permit application for any proposed new or modified facility or emissions unit subject to the preconstruction review requirements of Rule 62-212.400 or 62-212.500, F.A.C., the Department shall comply with all applicable provisions of Rule 62-103.150, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:

1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S., and the Department's analysis of the effect of the proposed construction or modification on ambient air quality, including the Department's preliminary determination of whether the permit should be approved or disapproved;
2. A 30-day period for submittal of public comments; and,

3. A notice, by advertisement in a newspaper of general circulation in the county affected, specifying the nature and location of the proposed facility or emissions unit, whether BACT or LAER has been determined, the degree of PSD increment consumption expected, if applicable, and the location of the information specified in paragraph 1. above; and notifying the public of the opportunity for submitting comments and requesting a public hearing.
- (b) The notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-103.150, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.
- (c) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall also be sent by the Department to the Regional Office of the U. S. Environmental Protection Agency and to all other state and local officials or agencies having cognizance over the location of such new or modified facility or emissions unit, including local air pollution control agencies, chief executives of city or county government, regional land use planning agencies, and any other state, Federal Land Manager, or Indian Governing Body whose lands may be affected by emissions from the new or modified facility or emissions unit.
- (d) A copy of the notice provided for in Rule 62-210.350(2)(a)3., F.A.C., shall be displayed in the appropriate district, branch and local program offices.
- (e) An opportunity for public hearing shall be provided in accordance with Chapter 120, F.S., and Rule 62-103.150, F.A.C.
- (f) Any public comments received shall be made available for public inspection in the location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., is available and shall be considered by the Department in making a final determination to approve or deny the permit.
- (g) The final determination shall be made available for public inspection at the same location where the information specified in Rule 62-210.350(2)(a)1., F.A.C., was made available.
- (h) For a proposed new or modified emissions unit which would be located within 100 kilometers of any Federal Class I area or whose emissions may affect any Federal Class I area, and which would be subject to the preconstruction review requirements of Rule 62-212.400, F.A.C., or Rule 62-212.500, F.A.C.:
1. The Department shall mail or transmit to the Administrator a copy of the initial application for an air construction permit and notice of every action related to the consideration of the permit application.
 2. The Department shall mail or transmit to the Federal Land Manager of each affected Class I area a copy of any written notice of intent to apply for an air construction permit; the initial application for an air construction permit, including all required analyses and demonstrations; any subsequently submitted information related to the application; the preliminary determination and notice of proposed agency action on the permit application; and any petition for an administrative hearing regarding the application or the Department's proposed action. Each such document shall be mailed or transmitted to the Federal Land Manager within fourteen (14) days after its receipt by the Department.
- (3) Additional Public Notice Requirements for Facilities Subject to Operation Permits for Title V Sources.
- (a) Before taking final agency action to issue a new, renewed, or revised air operation permit subject to Chapter 62-213, F.A.C., the Department shall comply with all applicable provisions of Rule 62-103.150, F.A.C., and provide an opportunity for public comment which shall include as a minimum the following:
1. A complete file available for public inspection in at least one location in the district affected which includes the information submitted by the owner or operator, exclusive of confidential records under Section 403.111, F.S.; and,
 2. A 30-day period for submittal of public comments.
- (b) The notice provided for in Rule 62-210.350(3)(a), F.A.C., shall be prepared by the Department and published by the applicant in accordance with all applicable provisions of Rule 62-103.150, F.A.C., except that the applicant shall cause the notice to be published no later than thirty (30) days prior to final agency action.
- (c) The notice shall identify:
1. The facility;
 2. The name and address of the office at which processing of the permit occurs;
 3. The activity or activities involved in the permit action;
 4. The emissions change involved in any permit revision;
 5. The name, address, and telephone number of a Department representative from whom interested persons may obtain additional information, including copies of the permit draft, the application, and all relevant supporting materials, including any permit application, compliance plan, permit, monitoring report, and compliance statement required pursuant to Chapter 62-213, F.A.C. (except for information entitled to confidential treatment pursuant to Section 403.111, F.S.), and all other materials available to the Department that are relevant to the permit decision;
 6. A brief description of the comment procedures required by Rules 62-103.150 and 62-210.350(3), F.A.C.;
 7. The time and place of any hearing that may be held, including a statement of procedure to request a hearing (unless a hearing has already been scheduled); and,

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

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

22. Administrative Permit Corrections.

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

- (a) Typographical errors noted in the permit;
- (b) Name, address or phone number change from that in the permit;
- (c) Any other similar minor administrative change at the source; and,
- (d) A change requiring more frequent monitoring or reporting by the permittee.
- (e) Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;
- (f) Changes listed at 40 CFR 72.83(a)(11), hereby adopted and incorporated by reference, to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 17-210.360(1)(e).

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

(3) For facilities subject to Chapter 62-213, F.A.C., a copy shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

(4) The Department shall incorporate requirements resulting from issuance of new or revised construction permits into existing operation permits issued pursuant to Chapter 62-213, F.A.C., if the construction permit revisions incorporate requirements of federally enforceable preconstruction review and if the applicant requests at the time of application that all of the requirements of Rule 62-213.430(1), F.A.C., be complied with in conjunction with the processing of the construction permit application.

[Rule 62-210.360, F.A.C.]

23. Reports.

(3) Annual Operating Report for Air Pollutant Emitting Facility.

(a) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year.

(c) The annual operating report shall be submitted to the appropriate Department District or Department approved local air pollution control program office by March 1 of the following year unless otherwise indicated by permit condition or Department request.

[Rule 62-210.370(3), F.A.C.]

24. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.

[Rule 62-210.650, F.A.C.]

25. Forms and Instructions. The forms used by the Department in the stationary source control program are adopted and incorporated by reference in this section. The forms are listed by rule number, which is also the form number, with the subject, title and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(1) Application for Air Permit - Long Form, Form and Instructions.

(a) Acid Rain Part (Phase II), Form and Instructions.

- 1. Repowering Extension Plan, Form and Instructions.
- 2. New Unit Exemption, Form and Instructions.
- 3. Retired Unit Exemption, Form and Instructions.

(b) Reserved.

(5) Annual Operating Report (AOR) for Air Pollutant Emitting Facility, Form and Instructions.

[Rule 62-210.900, F.A.C.]

Chapter 62-213, F.A.C.

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

[Rules 62-213.205 and 62-213.900(1), F.A.C.]

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

[Rule 62-213.205(1)(g), F.A.C.]

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

[Rule 62-213.205(1)(j), F.A.C.]

29. Annual Emissions Fee. DEP Form 62-213.900(1), F.A.C., "Major Air Pollution Source Annual Emissions Fee Form", must be completed by the permittee and submitted with the annual emissions fee.

[Rule 62-213.205(4), F.A.C.]

30. Air Operation Permit Fees. After December 31, 1992, no permit application processing fee, renewal fee, modification fee or amendment fee is required for an operation permit for a Title V source.

[Rule 62-213.205(5), F.A.C.]

31. Permits and Permit Revisions Required. All Title V sources are subject to the permit requirements of Chapter 62-213, F.A.C.

[Rule 62-213.400, F.A.C.]

32. No Title V source may operate except in compliance with Chapter 62-213, F.A.C.

[Rule 62-213.400(1), F.A.C.]

33. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation in each alternative method of operation:

(1) Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;

(2) Permitted sources may implement the terms or conditions of a new or revised construction permit if;

(a) The application for construction permit complied with the requirements of Rule 62-213.420(3) and (4), F.A.C.;

(b) The terms or conditions were subject to federally enforceable preconstruction review pursuant to Chapter 62-212, F.A.C.; and,

(c) The new or revised construction permit was issued after the Department and the applicant complied with all the requirements of Rule 62-213.430(1), F.A.C.;

(3) A permitted source may implement operating changes after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;

(a) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;

(b) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;

(4) Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

[Rule 62-213.410, F.A.C.]

34. Immediate Implementation Pending Revision Process.

(1) Those permitted Title V sources making any change that constitutes a modification pursuant to paragraph (a) of the definition of modification at Rule 62-210.200, F.A.C., but which would not constitute a modification pursuant to paragraph (b) of the same definition, may implement such change prior to final issuance of a permit revision in accordance with Rule 62-213.412, F.A.C., provided the change:

- (a) Does not violate any applicable requirement;
- (b) Does not contravene any permit term or condition for monitoring, testing, recordkeeping or reporting, or any compliance certification requirement;
- (c) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination of ambient impacts, or a visibility or increment analysis under the provisions of Chapter 62-212 or 62-296, F.A.C.;
- (d) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject including any federally enforceable emissions cap or federally enforceable alternative emissions limit.

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

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

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

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

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

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

35. Permit Applications.

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

(a) Timely Application.

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

(b) Complete Application.

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

2. For those applicants submitting initial permit applications pursuant to Rule 62-213.420(1)(a)1., F.A.C., a complete application shall be an application that substantially addresses all the information required by the application form number 62-210.900(1), and such applications shall be deemed complete within sixty days of receipt of a signed and certified application unless the Department notifies the applicant of incompleteness within that time. For all other applicants, the applications shall be deemed complete sixty days after receipt, unless the Department, within sixty days after receipt of a signed application for permit, permit revision or permit renewal, requests additional documentation or information needed to process the application. An applicant making timely and complete application for permit, or timely application for permit renewal as described by Rule 62-4.090(1), F.A.C., shall continue to operate the source

under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, provided the applicant complies with all the provisions of Rules 62-213.420(1)(b)3. and 4. F.A.C. Failure of the Department to request additional information within sixty days of receipt of a properly signed application shall not impair the Department's ability to request additional information pursuant to Rules 62-213.420(1)(b)3. and 4., F.A.C.

3. For those permit applications submitted pursuant to the provisions of Rule 62-213.420(1)(a)1., F.A.C., the Department shall notify the applicant if the Department becomes aware at any time during processing of the application that the application contains incorrect or incomplete information. The applicant shall submit the corrected or supplementary information to the Department within ninety days unless the applicant has requested and been granted additional time to submit the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days or such additional time as requested and granted shall render the application incomplete.

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

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

36. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA.

[Rule 62-213.420(2), F.A.C.]

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

[Rule 62-213.420(3), F.A.C.]

38. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

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

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

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

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subject to any condition listed at 40 CFR 70.7(f)(1), hereby adopted and incorporated by reference. The below requirements from 40 CFR 70.7(f) are adopted and incorporated by reference in Rule 62-213.430(4), F.A.C.:

o 40 CFR 70.7(f): Reopening for Cause.

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

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

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

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

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

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

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

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

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

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

41. Monitoring Information. All records of monitoring information shall specify the date, place, and time of sampling or measurement and the operating conditions at the time of sampling or measurement, the date(s) analyses were performed, the company or entity that performed the analyses, the analytical techniques or methods used, and the results of such analyses.

[Rule 62-213.440(1)(b)2.a., F.A.C.]

42. Retention of Records. Retention of records of all monitoring data and support information shall be for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

[Rule 62-213.440(1)(b)2.b., F.A.C.]

43. Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports.

[Rule 62-213.440(1)(b)3.a., F.A.C.]

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

[Rule 62-213.440(1)(b)3.b., F.A.C.]

45. Reports. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C.

[Rule 62-213.440(1)(b)3.c., F.A.C.]

46. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect.

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

47. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity.

[Rule 62-213.440(1)(d)3., F.A.C.]

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

[Rule 62-213.440(1)(d)4., F.A.C.]

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

[Rule 62-213.440(1)(d)5., F.A.C.]

50. Confidentiality Claims. Any permittee may claim confidentiality of any data or other information by complying with Rule 62-213.420(2), F.A.C.

[Rule 62-213.440(1)(d)6., F.A.C.]

51. Statement of Compliance. The permittee shall submit a statement of compliance with all terms and conditions of the permit. Such statement shall be submitted to the Department and EPA annually, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement. The statement of compliance shall include the identity of each term or condition of the permit for which each unit has remained in compliance during the period covered by the statement. The statement shall include identification of all methods used to demonstrate compliance and identification of each term or condition of the permit for which any unit has not remained in compliance during the period covered by the statement. For each term or condition for which the source has not remained in compliance during the period covered by the statement, the statement shall also identify each unit not in compliance and each term and condition with which the unit was not in compliance and state the inclusive dates that the source was not in compliance, the actions taken to achieve compliance and the method used to demonstrate compliance. Such statement shall be accompanied by a certification by a responsible official, in accordance with Rule 62-213.420(4), F.A.C.

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

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

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

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

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

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

Chapter 62-256, F.A.C.

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

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

Chapter 62-257. F.A.C.

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

[40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

Chapter 62-281. F.A.C.

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

- (1) Any facility having any refrigeration equipment normally containing 50 (fifty) pounds of refrigerant, or more, must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added;
- (2) No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided at 40 CFR 82.34, and properly uses equipment approved pursuant to 40 CFR 82.40;
- (3) No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or Class II substance at 40 CFR 82, Subpart A, Appendices A and B, except in compliance with Rule 62-281.100, F.A.C., and 40 CFR 82.34(B);
- (4) No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or Class II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined at 40 CFR 82.152) for service, maintenance or repair without using equipment certified for that type of appliance pursuant to 40 CFR 82.158 and without observing the practices set forth at 40 CFR 82.156;
- (5) No person may dispose of appliances (except small appliances, as defined at 40 CFR 82.152) without using equipment certified for that type of appliance pursuant to 40 CFR 82.158 and without observing the practices set forth at 40 CFR 82.156;
- (6) No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined at 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82, Subpart F.

[40 CFR 82; and, Chapter 62-281, F.A.C.]

Chapter 62-296. F.A.C.

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

- (a) Open burning is determined by the Department to be the only feasible method of operation and is authorized by an air permit issued pursuant to Chapter 62-210 or 62-213, F.A.C.; or
- (b) An emergency exists which requires immediate action to protect human health and safety; or
- (c) A county or municipality would use a portable air curtain incinerator to burn yard trash generated by a hurricane, tornado, fire or other disaster and the air curtain incinerator would otherwise be operated in accordance with the permitting exemption criteria of Rule 62-210.300(3), F.A.C.

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

58. Unconfined Emissions of Particulate Matter.

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

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

- a. Paving and maintenance of roads, parking areas and yards.
- b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing.
- c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar emissions units.
- d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the emissions unit to prevent reentrainment, and from buildings or work areas to prevent particulate from becoming airborne.
- e. Landscaping or planting of vegetation.
- f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter.
- g. Confining abrasive blasting where possible.
- h. Enclosure or covering of conveyor systems.

[Rules 62-296.320(4)(c)1. & 3., F.A.C.]

[electronic file name: tv-1.doc]

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

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

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

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

(c) Sampling Ports.

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

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) Access to Work Platform.

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

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

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

(f) Electrical Power.

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

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

(g) Sampling Equipment Support.

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

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

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

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

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

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

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

TABLE 297.310-1
CALIBRATION SCHEDULE

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

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

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

Pollutant (Circle One): SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

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

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

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

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

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

Name: _____

Signature: _____

Date: _____

Title: _____

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

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

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

FINDINGS OF FACT

1. The Florida Electric Power Coordinating Group, Incorporated, petitioned the Department to exempt those fossil fuel steam generators which have a heat input of more than 250 million Btu per hour and burn solid and/or liquid fuel less than 400 hours during the year from the requirement to conduct an annual particulate matter compliance test. [Exhibit 1]
2. Rule 62-296.405(1)(a), F.A.C., applies to those fossil fuel steam generators that are not subject to the federal standards of performance for new stationary sources (NSPS) in 40 CFR 60 and which have a heat input of more than 250 million Btu per hour.
3. Rule 62-296.405(1)(a), F.A.C., limits visible emissions from affected fossil fuel steam generators to, "20 percent opacity except for either one six-minute period per hour during which

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

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

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

6. Rule 297.310(7)(a)2., F.A.C., states, "The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision."

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

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

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

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

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

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

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

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

CONCLUSIONS OF LAW

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

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

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

ORDER

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

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

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

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

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

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

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

PETITION FOR ADMINISTRATIVE REVIEW

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

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

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

A petition must contain the following information:

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

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

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

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

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

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

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

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

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

A request for mediation must contain the following information:

BEST AVAILABLE COPY

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

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

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

The agreement to mediate must include the following:

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

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

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

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

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

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

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

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

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

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

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

The petition must specify the following information:

- (a) The name, address, and telephone number of the petitioner;
- (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;
- (c) Each rule or portion of a rule from which a variance or waiver is requested;
- (d) The citation to the statute underlying (implemented by) the rule identified in (c) above;
- (e) The type of action requested;
- (f) The specific facts that would justify a variance or waiver for the petitioner;
- (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and
- (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

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

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

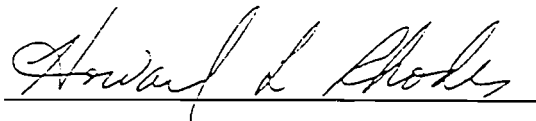
This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

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

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

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



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

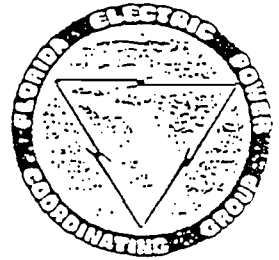
CERTIFICATE OF SERVICE

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

Clerk Stamp

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

Martha M. Wise 3-18-97
Clerk Date



January 28, 1997

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

RECEIVED

JAN 28 1997

BUREAU OF
AIR REGULATION

RE: Comments Regarding Draft Title V Permits

Dear Mr. Fancy:

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

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

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

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

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

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

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

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

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

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

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

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

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

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Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
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Title V implementation process, and we look forward to our meeting later this week. If you have any questions in the meantime, please call me at 561-625-7661.

Sincerely,

Rich Piper

Rich Piper, Chair *now*
FCG Air Subcommittee

Enclosures

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

33601

AP-42
FIFTH EDITION
JANUARY 1995

COMPILATION
OF
AIR POLLUTANT
EMISSION FACTORS

VOLUME I:
STATIONARY POINT
AND AREA SOURCES

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

January 1995

Exhibit 2

1.4 Natural Gas Combustion

1.4.1 General¹⁻²

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Section 5.3, Natural Gas Processing). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9500 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions And Controls³⁻⁵

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

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

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

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

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

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

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

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

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, and 1.4-3.⁶ For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

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

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

^a References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10⁶ cubic meters natural gas fired and lb of pollutant/10⁶ cubic feet natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

^b SCC = Source Classification Code.

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

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

Table 1.4-2 (Metric And English Units). EMISSION FACTORS FOR SULFUR DIOXIDE (SO₂), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION^a

Combustor Type (Size, 10 ⁶ Btu/hr Heat Input) (SCC) ^b	SO ₂ ^c			NO _x ^d			CO ^e		
	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING
Utility/large Industrial Boilers (> 100) (1-01-006-01, 1-01-006-04)									
Uncontrolled	9.6	0.6	A	8800	550 ^f	A	640	40	A
Controlled - Low NO _x burners	9.6	0.6	A	1300	81 ^f	D	ND	ND	NA
Controlled - Flue gas recirculation	9.6	0.6	A	850	53 ^f	D	ND	ND	NA
Small Industrial Boilers (10 - 100) (1-02-006-02)									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO _x burners	9.6	0.6	A	1300	81 ^f	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3 - < 10) (1-03-006-03)									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO _x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	ND	ND	NA
Residential Furnaces (<0.3) (No SCC)									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

^a Units are kg of pollutant/10⁶ cubic meters natural gas fired and lb of pollutant/10⁶ cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

^b SCC = Source Classification Code.

^c Reference 7. Based on average sulfur content of natural gas, 4600 g/10⁶ Nm³ (2000 gr/10⁶ scf).

Table 1.4-2 (cont.).

- ^d References 10,15-19. Expressed as NO_2 . For tangentially fired units, use $4400 \text{ kg}/10^6 \text{ m}^3$ ($275 \text{ lb}/10^6 \text{ ft}^3$). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1; Note that NO_x emissions from controlled boilers will be reduced at low load conditions.
- ^e References 9-10,16-18,20-21.
- ^f Emission factors apply to packaged boilers only.

Table 1.4-3 (Metric And English Units). EMISSION FACTORS FOR CARBON DIOXIDE (CO₂) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION^a

Combustor Type (Size, 10 ⁶ Btu/hr Heat Input) (SCC) ^b	CO ₂ ^c			TOC ^d		
	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	ND ^e	ND	NA	28 ^f	1.7 ^f	C
Small industrial boilers (10 - 100) (1-02-006-02)	1.9 E+06	1.2 E+05	D	92 ^g	5.8 ^g	C
Commercial boilers (0.3 - < 10) (1-03-006-03)	1.9 E+06	1.2 E+05	C	128 ^h	8.0 ^h	C
Residential furnaces (No SCC)	2.0 E+06	1.3 E+05	D	180 ^h	11 ^h	D

^a All factors represent uncontrolled emissions. Units are kg of pollutant/10⁶ cubic meters and lb of pollutant/10⁶ cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m³ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given factor by the ratio of the specified heating value to this average heating value. NA = not applicable.

^b SCC = Source Classification Code.

^c References 10,22-23.

^d References 9-10,18.

^e ND = no data.

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

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

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

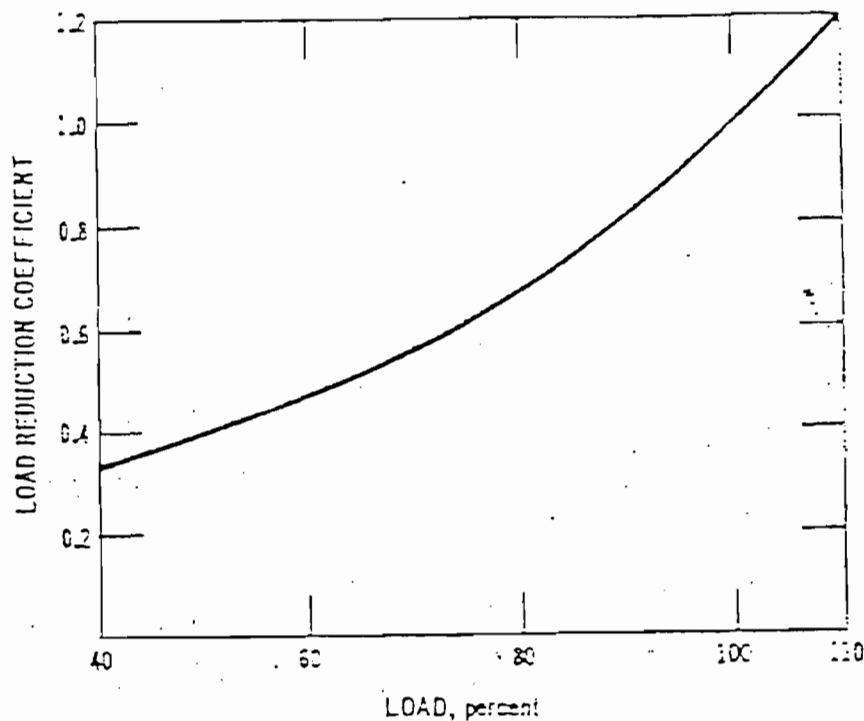
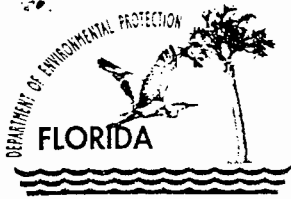


Figure 1.4-1. Load reduction coefficient as a function of boiler load.
(Used to determine NO_x reductions at reduced loads in large boilers.)

References For Section 1.4

1. *Exhaust Gases From Combustion and Industrial Processes*, EPA Contract No. EHSD 71-36, Engineering Science, Inc., Washington, DC, October 1971.
2. *Chemical Engineers' Handbook, Fourth Edition*, J. H. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.
3. *Background Information Document For Industrial Boilers*, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.
4. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.
5. *Fine Particulate Emissions From Stationary and Miscellaneous Sources in the South Coast Air Basin*, California Air Resources Board Contract No. A6-191-30, KVB, Inc., Tustin, CA, February 1979.
6. *Emission Factor Documentation for AP-42 Section 1.4 - Natural Gas Combustion (Draft)*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.
7. *Systematic Field Study of NO_x Emission Control Methods For Utility Boilers*, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.
8. *Compilation of Air Pollutants Emission Factors, Fourth Edition, AP-42*, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1985.

9. J. L. Muhlbaier, "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", *Journal of the Air Pollution Control Association*, December 1981.
10. *Field Investigation of Emissions From Combustion Equipment for Space Heating*, EPA-R2-73-084a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.
11. N. F. Suprenant, et al., *Emissions Assessment of Conventional Stationary Combustion Systems, Volume I: Gas and Oil Fired Residential Heating Sources*, EPA-600/7-79-029b, U. S. Environmental Protection Agency, Washington, DC, May 1979.
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13. N. F. Suprenant, et al., *Emissions Assessment of Conventional Stationary Combustion Systems, Volume IV: Commercial/Institutional Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.
14. N. F. Suprenant, et al., *Emissions Assessment of Conventional Stationary Combustion Systems, Volume V: Industrial Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.
15. *Emissions Test on 200 HP Boiler at Kaiser Hospital in Woodland Hills*, Energy Systems Associates, Tustin, CA, June 1986.
16. *Results From Performance Tests: California Milk Producers Boiler No. 5*, Energy Systems Associates, Tustin, CA, November 1984.
17. *Source Test For Measurement of Nitrogen Oxides and Carbon Monoxide Emissions From Boiler Exhaust at GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.
18. J. P. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.
19. *NO_x Emission Control Technology Update*, EPA Contract No. 68-01-6558, Radian Corporation, Research Triangle Park, NC, January 1984.
20. *Background Information Document For Small Steam Generating Units*, EPA-450/P-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.
21. *Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503*, American Gas Association Laboratories, Cleveland, OH, May 1975.
22. *Thirty-day Field Tests of Industrial Boilers: Site 5 - Gas-fired Low-NO_x Burner*, EPA-600/7-81-095a, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.
23. Private communication from Kim Black (Industrial Combustion) to Ralph Harris (MRJ), Independent Third Party Source Tests, February 7, 1992.



Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 9, 1997

Certified Mail - Return Receipt Requested

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

Dear Mr. Piper:

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

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

Sincerely,

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

MDH:ym

cc: Dotty Diltz, FDEP
Pat Comer, FDEP

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:

Florida Electric Power Coordinating Group, Inc.,)

Petitioner.)

ASP No. 97-B-01

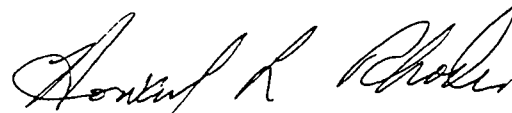
ORDER CORRECTING SCRIVENER'S ERROR

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

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

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

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



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

CERTIFICATE OF SERVICE

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

Clerk Stamp

FILING AND ACKNOWLEDGMENT

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

Martha Jewell Wise 7/10/97
Clerk Date

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
(version dated 02/05/97)

Abbreviations and Acronyms:

°F: Degrees Fahrenheit
BACT: Best Available Control Technology
CFR: Code of Federal Regulations
DEP: State of Florida, Department of Environmental Protection
DARM: Division of Air Resource Management
EPA: United States Environmental Protection Agency
F.A.C.: Florida Administrative Code
F.S.: Florida Statute
ISO: International Standards Organization
LAT: Latitude
LONG: Longitude
MMBtu: million British thermal units
MW: Megawatt
ORIS: Office of Regulatory Information Systems
SOA: Specific Operating Agreement
UTM: Universal Transverse Mercator

Citations:

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, guidance memorandums, permit numbers, and ID numbers.

Code of Federal Regulations:

Example: [40 CFR 60.334]

Where:	40	reference to	Title 40
	CFR	reference to	Code of Federal Regulations
	60	reference to	Part 60
	60.334	reference to	Regulation 60.334

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213, F.A.C.]

Where:	62	reference to	Title 62
	62-213	reference to	Chapter 62-213
	62-213.205	reference to	Rule 62-213.205, F.A.C.

ISO: International Standards Organization refers to those conditions at 288 degrees K, 60 percent relative humidity, and 101.3 kilopascals pressure.

**Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
(continued)**

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by state database.

Permit Numbers:

Example: 1050221-002-AV, or
1050221-001-AC

Where:

AC = Air Construction Permit
AV = Air Operation Permit (Title V Source)
105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by permit tracking database
001 or 002 = 3-digit sequential project number assigned by permit tracking database

Example: PSD-FL-185
PA95-01
AC53-208321

Where:

PSD= Prevention of Significant Deterioration Permit
PA = Power Plant Siting Act Permit
AC = old Air Construction Permit numbering

Revised Best Available Control Technology (BACT) Determination
 City of Vero Beach
 Indian River County

The applicant proposes to install a combustion turbine generator system at their facility in Vero Beach. The generator system will consist of a single 40 megawatt (MW) combustion turbine and a single heat recovery steam generator (HRSG) which will be used to repower an existing nominal 20 MW steam turbine.

The combustion turbine will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbine will use natural gas as the primary fuel and distillate oil as the backup fuel. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity for natural gas firing and 25% for oil-firing at ISO conditions to be as follows:

Pollutant	Potential Emissions (tons/yr)		PSD Significant Emission Rate (tons/yr)
	Natural Gas	Fuel Oil	
NO _x	328.5	132.5	40
SO ₂	1.3	130.8	40
PM	11.0	11.0	25
PM ₁₀	11.0	11.0	15
CO	43.8	11.0	100
VOC	21.9	5.5	40
H ₂ SO ₄	0.019	3.9	7
Be	0.0	0.0012	0.0004
Hg	0.0	0.0015	0.1
Pb	0.0	0.0125	0.6

Florida Administrative Code Rule 17-2.500(2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

May 9, 1991

BACT Determination Requested by the Applicant

<u>Pollutant</u>	<u>Determination</u>
NO _x	25 ppmvd @ 15% O ₂ (natural gas burning)* 65 ppmvd @ 15% O ₂ (No. 2 fuel oil firing)
SO ₂	Firing of natural gas or No. 2 fuel oil with a maximum sulfur content of 0.25%
PM and PM ₁₀	Combustion control
H ₂ SO ₄	Firing of No. 2 fuel oil with a maximum sulfur content of 0.25%
Be	Firing of No. 2 fuel oil

* The applicant proposes to install low NO_x combustors or SCR within one year after the date the combustion turbine commences commercial operation. The above NO_x emission limitations would apply only if low NO_x combustors are installed. If SCR is installed, the NO_x emission limitations would be 9 ppmvd or 25 ppmvd (@ 15% O₂) for natural gas or No. 2 fuel oil firing, respectively. Until installation of low NO_x combustors or SCR, the applicant proposes to limit NO_x emissions to 42 ppmvd and 65 ppmvd @ 15% oxygen when from natural gas and oil, respectively.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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 Best Available Control Technology 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 of BACT determinations 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 source in question the most stringent control available for a similar or identical source of source category. If it is shown that this level of control is technically or economically infeasible for the source 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 combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SO_x, NO_x, HCl, F1). 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., particulates, 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.

Combustion Products

The City of Vero Beach's projected emissions of particulate matter, PM₁₀, and beryllium surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2 for No. 2 fuel oil firing only. A review of the BACT/LAER Clearinghouse indicates that the applicants proposed emission rate (equivalent to 0.025 lb/MMBtu) is representative of BACT for turbines of similar size.

As this is the case, a PM/PM₁₀ emissions limitation of 0.025 lb/MMBtu for No. 2 fuel oil firing is reasonable as BACT for the Vero Beach facility.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium from turbines. BACT for these heavy metals is typically represented by the level of particulate control. As this is the case, the emission factor of 0.025 lb/MMBtu for particulate matter PM₁₀ is judged to also represent BACT for beryllium.

Products of Incomplete Combustion

The emissions of carbon monoxide and volatile organic compounds are each below the significant level and therefore do not require a BACT analysis.

Acid Gases

The emissions of sulfur dioxide, nitrogen oxides, and sulfuric acid mist, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of natural gas and No. 2 fuel oil with a maximum sulfur content of 0.25% to control sulfur dioxide emissions. A review of the latest edition (1990) of the BACT/LAER Clearinghouse indicates that sulfur dioxide emissions from combustion turbines have been controlled by limiting fuel oil sulfur content to a range of 0.1 to 0.3%, with the average for the facilities listed being approximately 0.24 percent. As this is the case, the applicant's proposal to use No. 2 fuel oil with a maximum sulfur content of 0.25% is judged to represent BACT.

The applicant has stated that BACT for nitrogen oxides (NO_x) will be complied with by installing low NO_x combustors capable of limiting NO_x emissions to 25 ppmvd or 65 ppmvd at 15% oxygen when burning natural gas or No. 2 fuel oil, respectively, or by installing selective catalytic reduction ("SCR") capable of limiting NO_x emissions to 9 ppmvd or 25 ppmvd at 15% oxygen when burning natural gas and No. 2 fuel oil, respectively, within one year after the date the new unit commences commercial operation. Until the installation of low NO_x combustors or SCR, wet injection will limit NO_x emissions from Unit 5 to 42 ppmvd or 65 ppmvd at 15% oxygen when burning natural gas or No. 2 fuel oil, respectively.

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 percent oxygen. This level of control

was accomplished through the use of water injection and a SCR system.

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 will decrease to approximately 86 percent.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 95 percent capacity factor is \$1,080,000. Taking into consideration the total levelized annual cost, a cost/benefit analysis of using SCR can now be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions with low NO_x combustors from the Vero Beach facility will be 186 tons/year, at a total levelized annual cost of \$377,000. Assuming that SCR would reduce the NO_x emissions by an additional 80%, the SCR would control 119 tons of NO_x annually for natural gas firing. When this reduction is taken into consideration with the incremental annual cost of \$703,000 (cost of SCR less cost of low NO_x combustors) the cost per ton of controlling NO_x is \$5,907. This cost (\$5,907/ton) exceeds costs that have been previously justified as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement is made:

"In order to reject a control program on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant.

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are also intended to operate at high capacity factors. As this is the case, the proposed project is similar to

other facilities in which SCR has been established as BACT, thereby supporting SCR as BACT for the proposed facility.

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases.

Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emissions limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

Assuming that the lowered ammonia injection ratio strategy was used to control NO_x emissions by 65%, the SCR would control 310 tons (62% of 503 tons/yr) of NO_x annually for oil firing. When this reduction is taken into consideration with the total annual cost of SCR, the cost per ton of controlling NO_x is \$4,630. This cost is lower than that determined for natural gas firing and is could be considered reasonable. However, when the proposed 25% capacity factor limit on oil-firing is taken into consideration, SCR technology is not cost effective.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages do not outweigh the benefit which would be provided

by reducing nitrogen oxide emissions by 80 percent. The overwhelming benefit of NO_x control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas and No. 2 fuel oil have been evaluated. Beryllium for oil fired operation exceeds PSD significant levels. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than 0.1 tons per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NO_x emissions with SCR, the applicant has identified the following technical limitations:

1. SCR would reduce output of combustion turbines by one percent.
2. SCR could result in the release of unreacted quantities of ammonia to the atmosphere.
3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.
4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

BACT Determination by DER

NO_x Control

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, capacity factors ranging from low to high). However, the cost and other concerns expressed by the applicant are valid.

The information that the applicant presented and Department calculations indicates that the incremental cost of

controlling NO_x with SCR (\$5,907/ton) for natural gas is high compared to other BACT determinations which require SCR. Although the cost of SCR for oil firing (\$4,630/ton) could be considered reasonable, when a 25% capacity factor limit on oil-firing is considered, SCR technology is not cost effective. Based on the information presented by the applicant and the studies conducted, the Department believes a permit requiring the use of SCR for NO_x control is not justifiable.

Pursuant to Florida Administrative Code ("FAC") Rule 17-2.630(3)(a), the Department may approve the use of a system of innovative control technology as BACT if:

1. The proposed system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function.

2. The owner or operator shall be required to achieve a level of continuous emissions reduction equivalent to that which would have been required under a Section 17-2.630(1) BACT determination within a reasonable period of time specified by the Department, but not later than four years from the time of startup or seven years from the date of issuance of the construction permit.

3. Use of the proposed system would not:

- a. Cause or contribute to a violation of any ambient air quality standard;
- b. Have a significant impact on any Class I area; or
- c. Have a significant impact on any area where an applicable maximum allowable increase is known to be violated.

"Innovative control technology" is defined as "[a]ny system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts." Rule 17-2.100(98), FAC.

Under the terms of the above rules, the low NO_x combustion system proposed by the City qualifies as a system of innovative control technology. Therefore, the Department has revised the permit to require retrofit installation of low

NOx combustors or SCR within one year of the date the new combustion turbine begins commercial operation. In accordance with the above BACT analysis, unless SCR is installed, No. 2 fuel oil firing must be limited to 25% of the annual capacity factor. However, if low NOx combustors are installed, and compliance testing establishes a NOx emissions rate of 42 ppmvd (at 15% O₂ on a dry basis) or lower, the annual limit on No. 2 fuel oil firing shall be 33% of the annual capacity factor. The additional capacity for oil firing at the 42 ppmvd NOx emissions rate is consistent with recent BACT determinations in Florida. In addition, in response to comments from EPA, simple cycle operation of the new unit shall be limited to 25% of the annual capacity factor during the first year of commercial operation and thereafter if SCR is installed.

SO₂ Control

For sulfur dioxide BACT is represented by firing natural gas or No. 2 fuel oil with an average sulfur content not to exceed 0.25 percent.

Other Emissions Control

The emission limitations for PM and PM₁₀, are based on previous BACT determinations for similar facilities, with the heavy metal beryllium being addressed through the particulate limitation and sulfuric acid mist being addressed through the sulfur dioxide limitation.

The emission limits for the City of Vero Beach project are thereby established as follows:

Pollutant	Emission Limit	
	Natural Gas Firing	No. 2 Fuel Oil Firing
NOx	25 ppmvd @ 15% O ₂	65 ppmvd @ 15% O ₂ *
SO ₂	Natural gas as fuel	Sulfur content not to exceed 0.25%
PM & PM ₁₀	0.006 lb/MMBtu	0.025 lb/MMBtu
Sulfuric Acid Mist	Emissions limited by natural gas and No. 2 fuel oil firing	
Beryllium	Emissions limited by natural gas and No. 2 fuel oil firing	

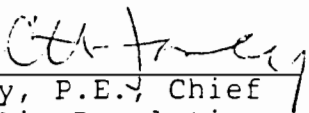
* The permittee must install low NOx combustors or SCR within one year after the date the combustion turbine commences commercial operation. The above NO_x emission limitations

apply only if low NOx combustors are installed. If SCR is installed, the NOx emission limitations will be 9 ppmvd or 25 ppmvd (@ 15% O₂) for natural gas or No. 2 fuel oil firing, respectively. Until low NOx combustors or SCR are installed, the permittee must limit NO_x emissions to 42 ppmvd and 65 ppmvd @ 15% oxygen when from natural gas and oil, respectively.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E., BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400


Recommended by:



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

June 17, 1991
Date

Approved by:



Carol M. Browner, Secretary
Dept. of Environmental Regulation

June 28, 1991
Date

Phase II Permit Application

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

This submission is: New Revised

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

Plant Name	<i>City of Vero Beach Municipal Power Plant</i>	State	<i>FL</i>	ORIS Code	<i>693</i>
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STEP 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

Compliance Plan					
a	b		c	d	e
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units	Commence Operation Date	New Units
					Monitor Certification Deadline
3	Yes	<i>No</i>			
4	Yes	<i>No</i>			
**5	Yes	<i>No</i>	<i>12/92</i>		<i>1/1/96</i>
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				
	Yes				

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

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

Plant Name (from Step 1)
City of Vero Beach Municipal Power Plant

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)
City of Vero Beach Municipal Power Plant

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.

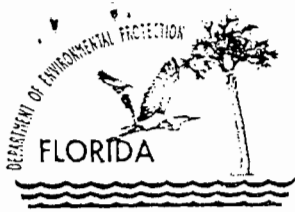
Certification

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 <i>Shuler W. Massey, Director of Power Resources</i>	
Signature <i>Shuler W. Massey</i>	Date <i>12-27-95</i>

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

AIRS 0610029
FINDS



Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 16, 1997

Mr. Rex Taylor
City Manager, Utilities Director
City of Vero Beach
PO Box 1389
Vero Beach, FL 32961-1389

Re: DRAFT Title V Permit No.: 0610029-002-AV
City of Vero Beach Municipal Utilities

Dear Mr. Taylor:

One copy of the DRAFT Title V Air Operation Permit for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River 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 within 30 (thirty) days of receipt of this letter. 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 Susan DeVore at 904/488-1344.

Sincerely,

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

CHF/sd

enclosures

In the Matter of an
Application for Permit by:

City of Vero Beach
1053 20th Place
Vero Beach, FL 32961-1389

DRAFT Permit No.: 0610029-002-AV
City of Vero Beach Municipal Utilities
Indian River 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 Vero Beach, applied on June 14, 1997, to the permitting authority for a Title V air operation permit for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River 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 within 30 (thirty) days 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: 904/488-1344; Fax: 904/922-6979), 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., or a party requests mediation as an alternative remedy under Section 120.573, F.S., before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the 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 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 (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, 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.

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

A request for mediation must contain the following information:

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

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and,

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

The agreement to mediate must include the following:

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

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

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

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

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

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

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

As provided in Section 120.573, F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, F.S., for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within 60 (sixty) days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department of Environmental Protection must enter an order incorporating the agreement of the parties in accordance with the provisions of Section 403.0872(7), F.S. If mediation terminates without settlement of the dispute, the permitting authority shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, F.S., remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply 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 410 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 7/17/97 to the person(s) listed:

Mr. Rex Taylor, City Manager, Utilities Director
Mr. Shuler W. Massey, Director of Power Resources

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, unless otherwise indicated, on the same date to the person(s) listed:

Mr. Kennard Kosky, P.E., Golder Associates
Mr. Richard M. Siefert, City of Vero Beach Power Plant
Mr. Len Kozlov P.E., DEP Central District
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)

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 7/17/97
(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.: 0610029-002-AV
City of Vero Beach Municipal Utilities
Indian River County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V air operation permit to City of Vero Beach for the City of Vero Beach Municipal Utilities located at 100 17th Street, Vero Beach, Indian River County. A case-by-case Maximum Achievable Control Technology (MACT) determination was not required in this permitting action. The applicant's name and address are: City of Vero Beach, Rex Taylor, City Manager, Utilities Director, City of Vero Beach, 1053 20th Place, PO Box 1389, Vero Beach, FL 32961-1389.

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 unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statutes (F.S.), or a party requests mediation as an alternative remedy under Section 120.573, F.S., before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the 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 (or a request for mediation, as discussed below) 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.

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

A request for mediation must contain the following information:

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

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and,

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

The agreement to mediate must include the following:

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

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

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

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

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

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

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

As provided in Section 120.573, F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, F.S., for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within 60 (sixty) days of the execution of the agreement. If mediation results in settlement of the administrative

dispute, the Department of Environmental Protection must enter an order incorporating the agreement of the parties in accordance with the provisions of Section 403.0872(7), F.S. If mediation terminates without settlement of the dispute, the permitting authority shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, F.S., remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, 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 410 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:

Permitting Authority:

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

Affected District/Local Program:

Central District
3319 Maguire Boulevard, Suite 232, Orlando, FL 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

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 904/488-1344, for additional information.

City of Vero Beach
City of Vero Beach Municipal Utilities
Facility ID No.: 0610029
Indian River County

Initial Title V Air Operation Permit
DRAFT Permit No.: 0610029-002-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: 904/488-1344
Fax: 904/922-6979

Drafted on July 15, 1997

Initial Title V Air Operation Permit
DRAFT Permit No.: 0610029-002-AV

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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 Vero Beach
PO Box 1389
Vero Beach, FL 32961-1389

DRAFT Permit No.: 0610029-002-AV
Facility ID No.: 0610029
SIC Nos.: 49, 4931
Project: Initial Title V Air Operation Permit

This permit is for the operation of the City of Vero Beach Municipal Utilities. This facility is located at 100 17th Street, Vero Beach, Indian River County; UTM Coordinates: Zone 17, 561.4 km East and 3056.5 km North; Latitude: 27° 37' 52" North and Longitude: 80° 22' 33" 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
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix TV-1, Title V Conditions (version dated 2/27/97)
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)
Phase II Acid Rain Application/Compliance Plan received 07/01/95
Alternate Sampling Procedure: ASP Number 97-B-01
BACT Determination dated June 28, 1991

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/sms/sd

Section I. Facility Information.

Subsection A. Facility Description.

This facility is an electric power generating plant located adjacent to a wastewater treatment facility and consists of:

Fossil Fuel Steam Generating Unit 1 (Emissions Unit 001), rated at 13 MW;

Fossil Fuel Steam Generating Unit 2 (Emissions Unit 002), rated at 17 MW;

Fossil Fuel Steam Generating Unit 3 (Emissions Unit 003), rated at 34 MW;

Fossil Fuel Steam Generating Unit 4 (Emissions Unit 004), rated at 56 MW;

Combined Cycle Gas Turbine Unit 5 (Emissions Unit 005), rated at 38 MW.

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 ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

Unregulated Emissions Units and/or Activities, See Appendix U-1	
006	Fuel oil, gasoline and lube oil storage tanks.
007	Waste water treatment plant.

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:

- Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
- Appendix H-1, Permit History/ID Number Changes
- Table 1-1, Summary of Air Pollutant Standards and Terms
- Table 2-1, Summary of Compliance Requirements

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 (version dated 2/27/97), 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. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]
3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4, F.A.C.]
4. Prevention of Accidental Releases (Section 112(r) of CAA). 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 (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
 - a. Tightly cover or close all VOC or OS containers when they are not in use.
 - b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
 - c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.

- d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.]

8. Not Federally Enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- a. Maintenance of paved areas as needed.
- b. Regular mowing of grass and care of vegetation.
- c. Limiting access to plant property by unnecessary vehicles.
- d. Care in handling and use of bagged chemical products.

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

Section III. Emissions Unit(s) and Conditions:

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

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1961.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	202	Natural Gas
-----	140	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

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

A.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil. Number 2 fuel oil may be used as an ignitor fuel.
 [Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

A.4. 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.
 [Rule 62-296.406(1), F.A.C.]

A.5. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
 [Rule 62-210.700(3), F.A.C.]

A.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content fuel oil. See specific condition **A.7.**

[Rule 62-296.406(2), F.A.C., BACT Determination 2/14/91]

A.7. Sulfur Dioxide - Sulfur Content. The fuel oil sulfur content shall not exceed 1.5 percent, by weight.

[Rule 62-296.406(3), F.A.C., BACT Determination 2/14/91]

Test Methods and Procedures

A.8. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery.

[Rules 62-213.440 and 62-296.406(3), F.A.C.]

A.9. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91.

[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.]

Monitoring of Operations

A.10. Annual Tests Required - VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

A.11. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

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

E.U. ID No.	Brief Description
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1961.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	248	Natural Gas
	243	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition F.14.

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

B.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil.

[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

B.4. 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.

[Rule 62-296.406(1), F.A.C.]

B.5. 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.]

B.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content fuel oil. See specific condition **B.7.**

[Rules 62-4.070(3) and 62-296.406(2), F.A.C., BACT for this source will be the same as that of the BACT Determination of 2/14/91 for EU 001]

B.7. Sulfur Dioxide - Sulfur Content. The fuel oil sulfur content shall not exceed 1.5 percent, by weight.

[Rules 62-4.070(3) and 62-296.406(3), F.A.C., BACT for this source will be the same as that of the BACT Determination of 2/14/91 for EU 001]

Test Methods and Procedures

B.8. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery.

[Rules 62-213.440 and 62-296.406(3), F.A.C.]

B.9. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91.

[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.]

Monitoring of Operations

B.10. Annual Tests Required - VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

B.11. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

Subsection C. This section addresses the following emissions unit.

003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
-----	--

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 3 began commercial operation in 1971.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
003	417	Natural Gas
	410	Fuel Oil

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

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

C.3. Methods of Operation. Fuels. The only fuel(s) allowed to be burned are any combination of natural gas and numbers 4 or 6 fuel oil.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

C.4. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(a), F.A.C.]

C.5. 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 3 has an operational continuous opacity monitor.]

C.6. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.

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

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

[Rule 62-210.700(3), F.A.C.]

C.8. 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.j., F.A.C.]

Test Methods and Procedures

C.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.]

C.10. Sulfur Dioxide. **The permittee elected to demonstrate compliance with the sulfur dioxide limitation 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 **C.11** and **C.12**.

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

C.11. 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 **C.12**.

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

C.12. The following fuel sampling and analysis program 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, or both ASTM D4057-88 and ASTM D129-91 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, 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 SO₂ 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.]

Monitoring of Operations

C.13. Annual Tests Required - PM and VE. Except as provided in specific conditions **F.6** through **F.8** of this permit, emission testing for particulate matter emissions and visible emissions 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. Testing shall be conducted while burning number 6 fuel oil.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

Common Conditions

C.14. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions.**

Subsection D. This section addresses the following emissions unit.

004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 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. The affected facility to which this subpart applies is fossil fuel steam generator, Unit 4, emissions unit 004. Fossil fuel fired steam generator Unit 4 began commercial operation in 1976.}

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:

Unit No.	mmBtu/hr Heat Input	Fuel Type
004	685	Natural Gas
	685	Fuel Oil

[Rules 62-4.160(2), 62-210.200(PTE)]

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 any combination of natural gas and numbers 4 or 6 fuel oil, except that firing of number 6 fuel oil is limited to no more than 32% of the total heat input to the boiler at any given time.
[Rule 62-213.410, F.A.C., AO 31-229058, 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 4 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.

(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.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 NO₂ in excess of:

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

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel

(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:

$$PS_{NO_x} = (86x + 130y) / (x + y)$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired;

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.

[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 SO₂ 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 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 SO₂ 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, SO₂, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

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

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

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

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

% O₂ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

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

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

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

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

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

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

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

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

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

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

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

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

(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) (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, SO₂ and NO_x may be determined by using the F_c factor, provided that the following procedure is used:

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

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

where:

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

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

%CO₂ = carbon dioxide concentration, percent dry basis.

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

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

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

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

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

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

(3) Particulate matter and SO₂ 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 SO₂ (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 SO₂ 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 O₂ concentration (%O₂) 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, SO₂ and NO_x. 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. Testing, if required, shall be conducted while burning number 6 fuel oil at a heat input of 32% of the total heat input to the boiler.

[Rules 62-4.070(3) and 62-213.440, F.A.C.]

D.14. Pursuant to 40 CFR 60.45 Emission and Fuel Monitoring.

CMS for Opacity Required, for NO_x and SO₂, Not Required.

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

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d).

(3) Notwithstanding 40 CFR 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under 40 CFR 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in 40 CFR 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required.

[40 CFR 60.45(a) & (b)]

Excess Emission Reports.

(g) Excess emission 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 report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions that shall be reported are defined as follows:

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

[40 CFR 60.45(g)]

Other NSPS Subpart D Conditions

D.15. 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.

Common Conditions

D.16. This emissions unit is also subject to conditions **F.1** through **F.19** contained in **Subsection F. Common Conditions**.

D.17. These emissions units are also subject to conditions **G.1** through **G.6** contained in **Subsection G. NSPS Common Conditions**.

Subsection E. This section addresses the following emissions unit.

005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.
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{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 combined cycle gas turbine, Unit 5. This unit underwent a BACT Determination dated June 28, 1991. BACT Limits were incorporated into the subsequent PSD permits including AC 31-253502 (PSD-FL-152B). Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 125 ft. stack. Emissions are controlled by dry low-NOx combustors, and by water injection when firing fuel oil. The turbine exhaust may also be vented through a bypass stack for simple cycle operation. The turbine began commercial operation in 1992.}

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:

Unit No.	mmBtu/hr Heat Input	Fuel Type
005	414*	Natural Gas
	455*	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.
 [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., and AC 31-253502 (PSD-FL-152B)]

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

E.3. Methods of Operation - Fuels. Any combination of only natural gas and number 2 fuel oil shall be fired in the combustion turbine.
 {Note: The limitations of specific conditions E.3 and E.6 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. The permitted fuel oil utilization rates for this emissions unit are:

- a. Maximum consumption of number 2 fuel oil shall not exceed 3,482 gal./hr.
- b. Maximum annual consumption of number 2 fuel oil shall not exceed 10,000,000 gal./yr.
- c. Maximum annual firing using number 2 fuel oil shall not exceed 33% of the annual capacity factor.

[Rules 62-4.070(3) and 62-213.440, F.A.C., and AC 31-253502 (PSD-FL-152B)]

Emission Limitations and Standards

E.5. Visible Emissions Visible emissions shall not exceed 10% opacity.
 [AC 31-253502 (PSD-FL-152B)]

E.6. Sulfur Dioxide - Sulfur Content. The No. 2 fuel oil sulfur content shall not exceed 0.25 percent, by weight. See specific conditions **E.12 and E.13**. The natural gas sulfur content shall not exceed 10 grains per hundred cubic feet (standard conditions). See specific condition **E.17**. {Note: The limitations of specific conditions **E.3 and E.6** are 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., and AC 31-253502 (PSD-FL-152B)]

E.7. The maximum allowable emissions from Unit 5 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Tons/Year ^{a, b}	
NOx ^c	25 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	243.7	BACT
SO2	Natural gas as fuel	0.25% S by weight	178.2	BACT
PM	0.006 lb/mmBtu	0.025 lb/mmBtu	23.7	BACT
VOC	0.0112 lb/mmBtu	0.0113 lb/mmBtu	21.0	BACT
CO	0.0224 lb/mmBtu	0.0226 lb/mmBtu	42.1	BACT

- a Tons per year based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing.
- b Based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.
- c NOx emission limit during co-firing of natural gas and number 2 fuel oil shall be determined by the following:

$$\text{NOx Limit} = \frac{(\text{Lg} \times \text{Qg}) + (\text{Lo} \times \text{Qo})}{\text{Qg} + \text{Qo}}$$

- where:
- Lg = Emission limit for natural gas
- Qg = Heat input of natural gas
- Lo = Emission limit for fuel oil
- Qo = Heat input of fuel oil

{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.}
 [AC 31-253502 (PSD-FL-152B) 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 through F.8 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 NO_x.

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., and AC 31-253502 (PSD-FL-152B)]

E.9. Testing for PM, CO, VOC. Except as provided in specific conditions F.6 through F.8 of this permit, emission testing for emissions of particulate matter and carbon monoxide shall be performed in the year prior to renewal of this permit, in accordance with specific condition E.10, while burning fuel oil. Emission testing for emissions of VOC shall be performed only if the CO test does not demonstrate compliance with the emissions limitation of specific condition E.7 of this permit. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests, if required, shall be conducted using EPA test method 25A.

[Rules 62-4.070(3) and 62-213.440, F.A.C., and AC 31-253502 (PSD-FL-152B)]

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. 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. 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.

[AC 31-253502 (PSD-FL-152B)]

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 D129-91 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.

[Rule 62-213.440, F.A.C., and , and AC 31-253502 (PSD-FL-152B)]

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.

[AC 31-253502 (PSD-FL-152B) and requested by applicant in the initial Title V permit application received June 27, 1996]

E.14. Excess Emissions by CEMS. The CEMS for NO_x shall be used to determine periods of excess emissions. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **E.7** of this permit. Periods of startup, shutdown, malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

{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) and 62-213.440, F.A.C.]

Record Keeping and Reporting Requirements

E.15. Natural Gas Sulfur Content Records Required. 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. Additional Reports Required. 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., and, AC 31-253502 (PSD-FL-152B)]

Other Conditions

E.17. Maintain SCR Duct Work. The permittee shall maintain duct work suitable for future installation of a selective catalytic reduction (SCR) system. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT. If an SCR system is installed, it may be bypassed during simple cycle operation.

[AC 31-253502 (PSD-FL-152B)]

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.**

Subsection F. Common Conditions.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW, 202 mmBtu/hr for natural gas and 140 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 4 fuel oil and number 2 fuel oil as an ignitor fuel, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 002.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW, 248 mmBtu/hr for natural gas and 243 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack shared with Emissions Unit 001.
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW, 417 mmBtu/hr for natural gas and 410 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

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

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

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.]

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.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62-210.300(4), F.A.C.

(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 shall 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.]

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. When VE Tests Not Required. 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 62-4.070(3), 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.}

F.9. Visible Emissions - Boiler 4, Turbine. The test method for visible emissions for emissions units 004 (Unit 4) and 005 (Turbine, Unit 5) 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 1, 2 and 3. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2) and 003 (Unit 3) 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 Central 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 Central District Air Section.
[Rule 62-210.700(6), F.A.C.]

F.18. Excess Emissions - Report. Submit to the Central 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., and AC 31-253502 (PSD-FL-152B)]

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 Central District Air Section on the results of each such test.
- (b) The required test report shall be filed with the Central 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 Central 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. NSPS Common Conditions.

<u>E.U. ID</u>	<u>Brief Description</u>
<u>No.</u> 004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW, 685 mmBtu/hr, capable of burning any combination of natural gas, number 6 fuel oil, and number 4 fuel oil, with emissions exhausted through a 200 ft. stack.
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW, 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas, capable of burning any combination of, number 2 fuel oil, and natural gas, with emissions exhausted through a 125 ft. stack.

{Note: The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected facilities to which this subpart applies are fossil fuel steam generator, Unit 4 and the combined cycle gas turbine, Unit 5.}

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 five years following the date of such measurements, maintenance, reports, and records.

[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

G.2. Pursuant to 40 CFR 60.8 Performance Tests.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining

compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

G.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

- (a) Compliance with standards in this part, other than opacity standards, shall be determined only by 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 IV. This section is the Acid Rain Part.

Operated by: City of Vero Beach
ORIS code: 0693

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

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

E.U. ID No.	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4
005	Combined Cycle Gas Turbine, Unit 5

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is 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 12/27/95.
 [Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO₂) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit is as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002
003	3	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	312*	312*	312*
		NO _x limit	**	**	**
004	4	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	106*	106*	106*
		NO _x limit	**	**	**
005	5	SO ₂ allowances, under Table 2 or 3 of 40 CFR Part 73	314*	314*	314*
		NO _x limit	**	**	**

* 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 NO_x requirements in accordance with the regulations implementing section 407 of the Clean Air Act.

A.3. Comments, notes, and justifications: None.

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

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
006	Fuel oil, gasoline and lube oil storage tanks. Tanks are: Tank 1 (1,560,000 gal. capacity) fuel oil; Tank 2 (3,108,000 gal. capacity) fuel oil; Tank 3 (350,000 gal. capacity) fuel oil; Diesel fuel tank for vehicles (500 gal. capacity); Gasoline fuel tank for vehicles (500 gal. capacity); Diesel tank for Unit 5 startup generator; Four lube oil tanks, one each for Units 1 - 4.
007	Waste water treatment plant, including headworks, liquid treatment processes and storage tanks.

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

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. Startup generator diesel engine associated with Unit 5.
2. Solvent use and hoods for laboratory.
3. Vapor extractor rooftop vents, one each for Units 1-4.
4. Cooling tower.

Appendix S
Permit Summary Tables

Table 1-1, Summary of Air Pollutant Emission Standards

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 40% for 2 min. each hour					Rule 62-296.406(1), F.A.C.	A.4, B.4
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60% opacity					Rule 62-210.700(3), F.A.C.	A.5, B.5
PM, SO ₂ Unit 1	Oil	8760	1.5% S by weight, fuel oil			230.2*	1008*	Rules 62-4.070(3) & 62-296.406(2), F.A.C., & BACT	A.6 & A.7, B.6 & B.7
PM, SO ₂ Unit 2	Oil	8760	1.5% S by weight, fuel oil			399.5*	1750*	Rules 62-4.070(3) & 62-296.406(2), F.A.C., & BACT	A.6 & A.7, B.6 & B.7

Notes for EU 001 & 002:

* Lb/hour and TPY values are for SO₂ emissions using fuel oil.

Appendix S
 Permit Summary Tables

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 40% for 2 min. each hour					Rule 62-296.405(1)(a), F.A.C.	C.4
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods)					Rule 62-210.700(3), F.A.C.	C.5
PM Steady State	Oil, Natural Gas	8760	0.1 lb/mmBtu			41*	179.6*	Rule 62-296.405(1)(b), F.A.C.	C.6
PM Soot Blowing or Load Change	Oil, Natural Gas	8760	0.3 lb/mmBtu			123*	67.3*	Rule 62-210.700(3), F.A.C.	C.7
SO ₂	Oil, Natural Gas	8760	2.75 lb/mmBtu			1127.5**	4938**	Rules 62-213.440, & 62-296.405(1)(c)1.j. F.A.C.	C.8

Notes for EU 003:

* Lb/hour and TPY values are for PM emissions using fuel oil.

** Lb/hour and TPY values are for SO₂ emissions using fuel oil.

Appendix S
 Permit Summary Tables

Emissions Unit	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions ^a			Equivalent Emissions ¹		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY	lb/hour	TPY		
VE Steady State	Oil, Natural Gas	8760	20% opacity, except for 27% for 6 min. each hour,					40 CFR 60.42(a)(2)	D.6
VE Soot Blowing or Load Change	Oil, Natural Gas	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods)					Rule 62-210.700(3), F.A.C.	D.4
PM Steady State	Oil, Natural Gas	8760	0.1 lb/mmBtu			68.5*	300*	40 CFR 60.42(a)(1)	D.6
PM Soot Blowing or Load Change	Oil, Natural Gas	8760	0.3 lb/mmBtu			205.5*	112.5*	Rule 62-210.700(3), F.A.C.	D.5
SO ₂	Oil, Natural Gas	8760	0.80 lb/mmBtu			548	2400	40 CFR 60.43(a)(1)	D.7
NO _x	Natural Gas	8760	0.20 lb/mmBtu			137	600.1	40 CFR 60.44(a)(1)	D.8
NO _x	Oil	8760	0.30 lb/mmBtu			205.5*	900.1*	40 CFR 60.44(a)(2)	D.8

Notes for EU 004:

* Lb/hour and TPY values for PM and NO_x emissions based on using number 4 fuel oil for total heat input.

a Firing of number 6 fuel oil is limited to no more than 32% of the total heat input to the boiler at any given time.

Appendix S
 Permit Summary Tables

Emissions Unit	Brief Description
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW.

Pollutant	Fuel(s)	Hours per Year	Allowable Emissions			Equivalent Emissions ¹		Regulatory Citations	See Permit Condition(s)
			Standard(s)	lb/hour	TPY ^a	lb/hour ^b	TPY ^b		
VE	No. 2 Fuel Oil, Natural Gas	8760	10 % opacity					AC 31-253502 (PSD-FL-152B)	E.5
SO ₂	"	8760	0.25% S by weight, fuel oil 10 gr S/ccf, natural gas		178.2	123		AC 31-253502 (PSD-FL-152B)	E.6
NO _x	No. 2 Fuel Oil	8760	42 ppmvd at 15% oxygen on a dry basis		243.7	79	114.2	AC 31-253502 (PSD-FL-152B)	E.7
NO _x	Natural Gas	8760	25 ppmvd at 15% oxygen on a dry basis		243.7	44.3	194	AC 31-253502 (PSD-FL-152B)	E.7
PM	No. 2 Fuel Oil	8760	0.025 lb/mmBtu		23.7	11.4	16.4	AC 31-253502 (PSD-FL-152B)	E.7
PM	Natural Gas	8760	0.006 lb/mmBtu		23.7	2.5	10.9	AC 31-253502 (PSD-FL-152B)	E.7
VOC	No. 2 Fuel Oil	8760	0.0113 lb/mmBtu		21.0	5.1	7.4	AC 31-253502 (PSD-FL-152B)	E.7
VOC	Natural Gas	8760	0.0112 lb/mmBtu		21.0	4.6	20.3	AC 31-253502 (PSD-FL-152B)	E.7
CO	No. 2 Fuel Oil	8760	0.0226 lb/mmBtu		42.1	10.3	14.9	AC 31-253502 (PSD-FL-152B)	E.7
CO	Natural Gas	8760	0.0224 lb/mmBtu		42.1	9.3	40.6	AC 31-253502 (PSD-FL-152B)	E.7

Appendix S
Permit Summary Tables

Notes for EU 005:

- a Tons per year based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing, based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.
- b Equivalent emissions based on 67% capacity factor for natural gas firing, 33% capacity factor number 2 fuel oil firing, based on 455 mmBtu/hr for number 2 fuel oil and 414 mmBtu/hr for natural gas.

Notes:

¹ The "Equivalent Emissions" listed are for informational purposes only. [Rule 62-213.205, F.A.C.]

NA = not applicable

**Appendix S
 Permit Summary Tables**

Table 2-1, Summary of Compliance Requirements

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 13 MW.
002	Fossil Fuel Steam Generator, Unit 2, rated at 17 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	DEP Method 9	Annual	August 1st	1 hour	No	A.10, B.10
PM, SO ₂	Oil	Fuel Sampling & Analysis	As Fired			No	A.8 & A.9, B.8 & B.9

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3, rated at 34 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	DEP Method 9	Annual	August 1st	1 hour	No	C.13
PM	"	EPA Test Methods 17, 5, 5B, or 5F	Annual	August 1st	3 hours	No	C.9, C.13
SO ₂	"	Fuel Sampling & Analysis	As Fired			No	C.10, C.11, C.12

Appendix S
Permit Summary Tables

Emissions Unit	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, rated at 56 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	Oil, Natural Gas	EPA Method 9	Annual	August 1st	1 hour	No	D.9, D.12
PM	"	EPA Test Methods 5, 5B, or 17	Annual	August 1st	3 hours	No	D.6, D.9, D.12
SO ₂	"	Fuel Sampling & Analysis	As Fired			No	D.7, D.12
NO _x	"	EPA Test Methods 7, 7A, 7C, 7D, or 7E	Annual	August 1st	3 hours	No	D.9, D.12

**Appendix S
 Permit Summary Tables**

Emissions Unit	Brief Description
005	Combined Cycle Gas Turbine, Unit 5, rated at 38 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date ¹	Minimum Compliance Test Duration	CMS ²	See Permit Condition(s)
VE	No 2 Fuel Oil, Natural Gas	EPA Method 9	Annual	August 1st	1 hour	No	E.8
SO ₂	"	Fuel Sampling & Analysis	As Fired			Yes*	E.6, E.12, E.17
NO _x	No 2 Fuel Oil, Natural Gas	EPA Test Method 20	Annual	August 1st	3 hours	Yes	E.8
PM	"	EPA Test Methods 5 or 17	Prior to Renewal		3 hours	No	E.9
VOC	"	EPA Test Method 10	Only if CO test fails			No	E.9
CO	"	EPA Test Method 25A	Prior to Renewal			No	E.9

Notes for EU 005:

* Continuous monitoring of fuel consumption required.

Notes:

¹ Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.

² CMS = continuous monitoring system

See also Section F for general testing requirements.

**Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
(version dated 02/05/97)**

Abbreviations and Acronyms:

°F: Degrees Fahrenheit
BACT: Best Available Control Technology
CFR: Code of Federal Regulations
DEP: State of Florida, Department of Environmental Protection
DARM: Division of Air Resource Management
EPA: United States Environmental Protection Agency
F.A.C.: Florida Administrative Code
F.S.: Florida Statute
ISO: International Standards Organization
LAT: Latitude
LONG: Longitude
MMBtu: million British thermal units
MW: Megawatt
ORIS: Office of Regulatory Information Systems
SOA: Specific Operating Agreement
UTM: Universal Transverse Mercator

Citations:

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, guidance memorandums, permit numbers, and ID numbers.

Code of Federal Regulations:

Example: [40 CFR 60.334]

Where:	40	reference to	Title 40
	CFR	reference to	Code of Federal Regulations
	60	reference to	Part 60
	60.334	reference to	Regulation 60.334

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213, F.A.C.]

Where:	62	reference to	Title 62
	62-213	reference to	Chapter 62-213
	62-213.205	reference to	Rule 62-213.205, F.A.C.

ISO: International Standards Organization refers to those conditions at 288 degrees K, 60 percent relative humidity, and 101.3 kilopascals pressure.

**Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
(continued)**

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by state database.

Permit Numbers:

Example: 1050221-002-AV, or
1050221-001-AC

Where:

AC = Air Construction Permit
AV = Air Operation Permit (Title V Source)
105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by permit tracking database
001 or 002 = 3-digit sequential project number assigned by permit tracking database

Example: PSD-FL-185
PA95-01
AC53-208321

Where:

PSD = Prevention of Significant Deterioration Permit
PA = Power Plant Siting Act Permit
AC = old Air Construction Permit numbering

Revised Best Available Control Technology (BACT) Determination
 City of Vero Beach
 Indian River County

The applicant proposes to install a combustion turbine generator system at their facility in Vero Beach. The generator system will consist of a single 40 megawatt (MW) combustion turbine and a single heat recovery steam generator (HRSG) which will be used to repower an existing nominal 20 MW steam turbine.

The combustion turbine will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbine will use natural gas as the primary fuel and distillate oil as the backup fuel. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity for natural gas firing and 25% for oil-firing at ISO conditions to be as follows:

Pollutant	Potential Emissions (tons/yr)		PSD Significant Emission Rate (tons/yr)
	Natural Gas	Fuel Oil	
NO _x	328.5	132.5	40
SO ₂	1.3	130.8	40
PM _{2.5}	11.0	11.0	25
PM ₁₀	11.0	11.0	15
CO	43.8	11.0	100
VOC	21.9	5.5	40
H ₂ SO ₄	0.019	3.9	7
Be	0.0	0.0012	0.0004
Hg	0.0	0.0015	0.1
Pb	0.0	0.0125	0.6

Florida Administrative Code Rule 17-2.500(2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

May 9, 1991

BACT Determination Requested by the Applicant

<u>Pollutant</u>	<u>Determination</u>
NO _x	25 ppmvd @ 15% O ₂ (natural gas burning)* 65 ppmvd @ 15% O ₂ (No. 2 fuel oil firing)
SO ₂	Firing of natural gas or No. 2 fuel oil with a maximum sulfur content of 0.25%
PM and PM ₁₀	Combustion control
H ₂ SO ₄	Firing of No. 2 fuel oil with a maximum sulfur content of 0.25%
Be	Firing of No. 2 fuel oil

- * The applicant proposes to install low NO_x combustors or SCR within one year after the date the combustion turbine commences commercial operation. The above NO_x emission limitations would apply only if low NO_x combustors are installed. If SCR is installed, the NO_x emission limitations would be 9 ppmvd or 25 ppmvd (@ 15% O₂) for natural gas or No. 2 fuel oil firing, respectively. Until installation of low NO_x combustors or SCR, the applicant proposes to limit NO_x emissions to 42 ppmvd and 65 ppmvd @ 15% oxygen when from natural gas and oil, respectively.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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 Best Available Control Technology 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 of BACT determinations 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 source in question the most stringent control available for a similar or identical source of source category. If it is shown that this level of control is technically or economically infeasible for the source 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 combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SO_x, NO_x, HCl, F1). 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., particulates, 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.

Combustion Products

The City of Vero Beach's projected emissions of particulate matter, PM₁₀, and beryllium surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2 for No. 2 fuel oil firing only. A review of the BACT/LAER Clearinghouse indicates that the applicants proposed emission rate (equivalent to 0.025 lb/MMBtu) is representative of BACT for turbines of similar size.

As this is the case, a PM/PM₁₀ emissions limitation of 0.025 lb/MMBtu for No. 2 fuel oil firing is reasonable as BACT for the Vero Beach facility.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium from turbines. BACT for these heavy metals is typically represented by the level of particulate control. As this is the case, the emission factor of 0.025 lb/MMBtu for particulate matter PM₁₀ is judged to also represent BACT for beryllium.

Products of Incomplete Combustion

The emissions of carbon monoxide and volatile organic compounds are each below the significant level and therefore do not require a BACT analysis.

Acid Gases

The emissions of sulfur dioxide, nitrogen oxides, and sulfuric acid mist, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of natural gas and No. 2 fuel oil with a maximum sulfur content of 0.25% to control sulfur dioxide emissions. A review of the latest edition (1990) of the BACT/LAER Clearinghouse indicates that sulfur dioxide emissions from combustion turbines have been controlled by limiting fuel oil sulfur content to a range of 0.1 to 0.3%, with the average for the facilities listed being approximately 0.24 percent. As this is the case, the applicant's proposal to use No. 2 fuel oil with a maximum sulfur content of 0.25% is judged to represent BACT.

The applicant has stated that BACT for nitrogen oxides (NO_x) will be complied with by installing low NO_x combustors capable of limiting NO_x emissions to 25 ppmvd or 65 ppmvd at 15% oxygen when burning natural gas or No. 2 fuel oil, respectively, or by installing selective catalytic reduction ("SCR") capable of limiting NO_x emissions to 9 ppmvd or 25 ppmvd at 15% oxygen when burning natural gas and No. 2 fuel oil, respectively, within one year after the date the new unit commences commercial operation. Until the installation of low NO_x combustors or SCR, wet injection will limit NO_x emissions from Unit 5 to 42 ppmvd or 65 ppmvd at 15% oxygen when burning natural gas or No. 2 fuel oil, respectively.

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 percent oxygen. This level of control

was accomplished through the use of water injection and a SCR system.

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 will decrease to approximately 86 percent.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 95 percent capacity factor is \$1,080,000. Taking into consideration the total levelized annual cost, a cost/benefit analysis of using SCR can now be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions with low NO_x combustors from the Vero Beach facility will be 186 tons/year, at a total levelized annual cost of \$377,000. Assuming that SCR would reduce the NO_x emissions by an additional 80%, the SCR would control 119 tons of NO_x annually for natural gas firing. When this reduction is taken into consideration with the incremental annual cost of \$703,000 (cost of SCR less cost of low NO_x combustors) the cost per ton of controlling NO_x is \$5,907. This cost (\$5,907/ton) exceeds costs that have been previously justified as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement is made:

"In order to reject a control program on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant.

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are also intended to operate at high capacity factors. As this is the case, the proposed project is similar to

other facilities in which SCR has been established as BACT, thereby supporting SCR as BACT for the proposed facility.

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases.

Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emissions limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

Assuming that the lowered ammonia injection ratio strategy was used to control NO_x emissions by 65%, the SCR would control 310 tons (62% of 503 tons/yr) of NO_x annually for oil firing. When this reduction is taken into consideration with the total annual cost of SCR, the cost per ton of controlling NO_x is \$4,630. This cost is lower than that determined for natural gas firing and is could be considered reasonable. However, when the proposed 25% capacity factor limit on oil-firing is taken into consideration, SCR technology is not cost effective.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages do not outweigh the benefit which would be provided

by reducing nitrogen oxide emissions by 80 percent. The overwhelming benefit of NO_x control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas and No. 2 fuel oil have been evaluated. Beryllium for oil fired operation exceeds PSD significant levels. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than 0.1 tons per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NO_x emissions with SCR, the applicant has identified the following technical limitations:

1. SCR would reduce output of combustion turbines by one percent.
2. SCR could result in the release of unreacted quantities of ammonia to the atmosphere.
3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.
4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

BACT Determination by DER

NO_x Control

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, capacity factors ranging from low to high). However, the cost and other concerns expressed by the applicant are valid.

The information that the applicant presented and Department calculations indicates that the incremental cost of

controlling NO_x with SCR (\$5,907/ton) for natural gas is high compared to other BACT determinations which require SCR. Although the cost of SCR for oil firing (\$4,630/ton) could be considered reasonable, when a 25% capacity factor limit on oil-firing is considered, SCR technology is not cost effective. Based on the information presented by the applicant and the studies conducted, the Department believes a permit requiring the use of SCR for NO_x control is not justifiable.

Pursuant to Florida Administrative Code ("FAC") Rule 17-2.630(3)(a), the Department may approve the use of a system of innovative control technology as BACT if:

1. The proposed system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function.
2. The owner or operator shall be required to achieve a level of continuous emissions reduction equivalent to that which would have been required under a Section 17-2.630(1) BACT determination within a reasonable period of time specified by the Department, but not later than four years from the time of startup or seven years from the date of issuance of the construction permit.
3. Use of the proposed system would not:
 - a. Cause or contribute to a violation of any ambient air quality standard;
 - b. Have a significant impact on any Class I area; or
 - c. Have a significant impact on any area where an applicable maximum allowable increase is known to be violated.

"Innovative control technology" is defined as "[a]ny system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts." Rule 17-2.100(98), FAC.

Under the terms of the above rules, the low NO_x combustion system proposed by the City qualifies as a system of innovative control technology. Therefore, the Department has revised the permit to require retrofit installation of low

NOx combustors or SCR within one year of the date the new combustion turbine begins commercial operation. In accordance with the above BACT analysis, unless SCR is installed, No. 2 fuel oil firing must be limited to 25% of the annual capacity factor. However, if low NOx combustors are installed, and compliance testing establishes a NOx emissions rate of 42 ppmvd (at 15% O₂ on a dry basis) or lower, the annual limit on No. 2 fuel oil firing shall be 33% of the annual capacity factor. The additional capacity for oil firing at the 42 ppmvd NOx emissions rate is consistent with recent BACT determinations in Florida. In addition, in response to comments from EPA, simple cycle operation of the new unit shall be limited to 25% of the annual capacity factor during the first year of commercial operation and thereafter if SCR is installed.

SO₂ Control

For sulfur dioxide BACT is represented by firing natural gas or No. 2 fuel oil with an average sulfur content not to exceed 0.25 percent.

Other Emissions Control

The emission limitations for PM and PM₁₀, are based on previous BACT determinations for similar facilities, with the heavy metal beryllium being addressed through the particulate limitation and sulfuric acid mist being addressed through the sulfur dioxide limitation.

The emission limits for the City of Vero Beach project are thereby established as follows:

Pollutant	Emission Limit	
	Natural Gas Firing	No. 2 Fuel Oil Firing
NOx	25 ppmvd @ 15% O ₂	65 ppmvd @ 15% O ₂ *
SO ₂	Natural gas as fuel	Sulfur content not to exceed 0.25%
PM & PM ₁₀	0.006 lb/MMBtu	0.025 lb/MMBtu
Sulfuric Acid Mist	Emissions limited by natural gas and No. 2 fuel oil firing	
Beryllium	Emissions limited by natural gas and No. 2 fuel oil firing	

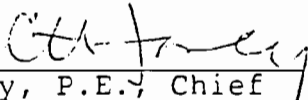
* The permittee must install low NOx combustors or SCR within one year after the date the combustion turbine commences commercial operation. The above NO_x emission limitations

apply only if low NOx combustors are installed. If SCR is installed, the NOx emission limitations will be 9 ppmvd or 25 ppmvd (@ 15% O₂) for natural gas or No. 2 fuel oil firing, respectively. Until low NOx combustors or SCR are installed, the permittee must limit NO_x emissions to 42 ppmvd and 65 ppmvd @ 15% oxygen when from natural gas and oil, respectively.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E., BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:



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

June 17, 1991
Date

Approved by:





Carol M. Browner, Secretary
Dept. of Environmental Regulation

June 28, 1991
Date

MEMORANDUM

TO: Scott M. Sheplak, P.E.

FROM:  Joseph Kahn, P.E.,  Susan C. DeVore

DATE: July 15, 1997

RE: Intent package for DRAFT Permit No.: 0610029-002-AV
City of Vero Beach
Municipal Utilities

This permit is for the initial Title V air operation permit for the subject facility which is a municipal power plant with four boilers and one gas turbine. Unregulated emissions units include the adjacent waste water treatment facility.

No additional information was requested. This application was complete on date received, June 14, 1996. Written comments were not received from the Central District office.

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

The requirements of the PSD permit for the turbine are more restrictive than the NSPS Subpart GG requirements. We drafted the permit to reflect primarily the PSD requirements with a note, where appropriate, indicating that compliance with the NSPS requirements would be assured by satisfying the PSD requirements. The requirements for fuel monitoring were eliminated, for example, because the applicant has agreed to utilize NO_x CEMS to monitor for excess emissions. The applicant had included a custom fuel monitoring schedule, which we forwarded to Mike Harley to obtain EPA approval, but the schedule was not included in the draft permit. Some PSD requirements were re-written to simplify the permit.

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

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

3. _____

1. Clair Kincy

4. _____

2. _____

5. _____

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

YOUR SIGNATURE

____ DUE DATE _____

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

____ FOR YOUR FILES

COMMENTS:

Re: DRAFT Title V Permit
No. 0610029-002-AV

City of Vero Beach

I recommend issuance.
This is Joe & Susan's 1st
DRAFT Title V permit.

FROM:

Scott Staplak

DATE:

7/15

PHONE:

Florida's DRAFT Permit Electronic Notification Cover Memorandum

TO: Yolanda Adams, U.S. EPA Region 4
CC: Carla E. Pierce, U.S. EPA Region 4
THRU: Scott M. Sheplak, P.E., Tallahassee Title V Section
FROM: Susan C. DeVore, Permit Engineer
DATE: July 14, 1997
RE: U.S. EPA Region 4 DRAFT Title V Operation Permit Review

The following DRAFT Title V operation permits and associated documents have been posted on the DEP World Wide Web Internet site for your review. Please provide any comments via. Internet E-mail, to Scott M. Sheplak, P.E., at "Sheplak_S@dep.state.fl.us".

<u>Applicant Name</u> <u>Name(s)</u>	<u>County</u>	<u>Method of Transmittal</u>	<u>Electronic File</u>
City of Vero Beach	Indian River	INTERNET	0610029d.zip

This zipped file contains the following electronic files:

0610029i.doc
0610029d.doc
etc.