Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 5, 2001

Mr. Walter P. Bussells
CEO and Managing Director
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Re: DRAFT Title V Permit Revision No.: 0310045-008-AV
Statement of Basis
Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

Dear Mr. Bussells:

Please replace the attached Statement of Basis with the one that was sent to you on December 3rd, regarding the above referenced permitting action. There were two references to air construction permits that were incorrectly cited in the 3rd paragraph, which were 0310046-005-AC and 0310047-006-AC, that should have been 0310045-005-AC and 0310045-006-AC, respectively. I apologize for the errors.

If you have any questions, please call me at 850/413-9198.

Sincerely,

R. Bruce Mitchell
Environmental Administrator
Bureau of Air Regulation
Title V Section

BM/m

Attachment

cc: Mr. Jon P. Eckenbach, Executive Vice President/Designated Representative, JEA
Mr. Kennard F. Kosky, P.E., GAI
Mr. Bert Gianazza, JEA, Application Contact
Mr. Richard Robinson, AWQD

STATEMENT OF BASIS

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Facility ID No.: 0310045
Duval County

Title V Air Operation Permit Revision
DRAFT Permit No.: 0310045-008-AV

The initial Title V Air Operation Permit, No. 0310045-001-AV, was issued October 13, 1998, and effective on January 1, 1999.

This Title V Air Operation Permit Revision 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.

The purpose of the revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 simple cycle combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. The installation of the foggers was authorized in air construction permit No. 0310045-004-AC. A change in the testing requirements was addressed in air construction permit No. 0310045-005-AC; and finally, a reduction in the hours of operation and initial testing requirements were addressed in air construction permit No. 0310045-006-AC. Therefore, Specific Condition C.4. will be changed and a new Specific Condition C.20. will be added as follows:

FROM:
C.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO16-173886]

TO:
C.4. Hours of Operation.
a. These CTs may operate continuously, i.e., 8,760 hours/year.
b. Each CT shall not exceed 399 hrs/yr operation while using foggers.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AO16-173886; and, 0310045-006-AC]

and,

new:
C.20. Foggers. A log book shall be maintained to show when each CT is using a fogger device and shall provide the beginning and ending times (hour and minute) of its use. See Specific Condition **C.4.b.**
[Rule 62-4.070(3), F.A.C.]

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 28, 2001

Mr. Walter P. Bussells
CEO and Managing Director
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Re: DRAFT Title V Permit Revision No.: 0310045-008-AV
Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

Dear Mr Bussells:

One copy of the DRAFT Title V Air Operation Permit Revision for the Jacksonville Electric Authority's Northside Generating Station/St. Johns River Power Park located at 4377 Heckscher Drive, Jacksonville, Duval County, is enclosed. This permit revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. The permitting authority's "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" and the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" must be published as soon as possible. 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 Bruce Mitchell at 850/413-9198.

Sincerely,

for Scott M. Sheplak
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BM/m

Enclosures

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Walter P. Bussells
CEO and Managing Director
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* T. HEANEY

B. Date of Delivery

C. Signature X L. Heaney ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

DEC 10 2001

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)* 7000 0520 0020 9371 1823

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Mr. Walter P. Bussells

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Recipient's Name (Please Print Clearly) (To be completed by mailer)
Mr. Walter P. Bussells
Street, Apt. No.; or PO Box No.
21 West Church Street
City, State, ZIP+4
Jacksonville, Florida 32202

PS Form 3800, February 2000 See Reverse for Instructions

7000 0520 0020 9371 1823

STATEMENT OF BASIS

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Facility ID No.: 0310045
Duval County

Title V Air Operation Permit Revision
DRAFT Permit No.: 0310045-008-AV

The initial Title V Air Operation Permit, No. 0310045-001-AV, was issued October 13, 1998, and effective on January 1, 1999.

This Title V Air Operation Permit Revision 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.

The purpose of the revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 simple cycle combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. The installation of the foggers was authorized in air construction permit No. 0310045-004-AC. A change in the testing requirements was addressed in air construction permit No. 0310046-005-AC; and finally, a reduction in the hours of operation and initial testing requirements were addressed in air construction permit No. 0310047-006-AC. Therefore, Specific Condition C.4. will be changed and a new Specific Condition C.20. will be added as follows:

FROM:
C.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO16-173886]

TO:
C.4. Hours of Operation.
a. These CTs may operate continuously, i.e., 8,760 hours/year.
b. Each CT shall not exceed 399 hrs/yr operation while using foggers.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AO16-173886; and, 0310045-006-AC]

and,

new:
C.20. Foggers. A log book shall be maintained to show when each CT is using a fogger device and shall provide the beginning and ending times (hour and minute) of its use. See Specific Condition **C.4.b.**
[Rule 62-4.070(3), F.A.C.]

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

Department of
Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

DRAFT Permit No.: 0310045-008-AV
Facility ID No.: 0310045

Project type: Title V Air Operation Permit Revision – Water Spray Fogging Devices

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

Scott M. Sheplak 11/25/03

Scott M. Sheplak, P.E. date
Registration Number: 48866

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/921-9532
Fax: 850/922-6979

In the Matter of an
Application for Permit Revision by:

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

DRAFT Permit No.: 0310045-008-AV
Northside Generating Station/St. Johns River Power Park
Duval County

_____________________________/

INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

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

The permittee, Jacksonville Electric Authority, submitted a request on October 5, 2001, for a permit revision. The purpose for the revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 simple cycle combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. The JEA's Northside Generating Station/St. Johns River Power Park are located at 4377 Berkscher Drive, Jacksonville, Duval County.

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

The permitting authority intends to issue this Title V Air Operation Permit Revision 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.; the City of Jacksonville Ordinance Code, Title X, Chapter 376; and, the Jacksonville Environmental Protection Board Rule 2, Parts I thru VII and Parts IX thru XII.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 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 REVISION." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-1344; Fax: 850/922-6979), within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106, F.A.C.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the attached 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 the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." 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.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/488-9730; Fax: 850/487-4938). Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when each petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and,

(f) A demand for relief.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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.

Mediation will not be available in this proceeding.

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: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

for 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 REVISION (including the PUBLIC NOTICE and the DRAFT Permit) and all copies were sent by certified mail before the close of business on 12/3/01 to the person(s) listed:

Mr. Walter P. Bussells, CEO and Managing Director/Responsible Official, JEA

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

Mr. Jon P. Eckenbach, Executive Vice President/Designated Representative, JEA
Mr. Kennard F. Kosky, P.E., GAI
Mr. Bert Gianazza, JEA, Application Contact

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the DRAFT Permit package) were sent by INTERNET E-mail on the same date to the person(s) listed:

Mr. Richard Robinson, AWQD
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

12/3/01
cc: Bruce Mitchell
Reading File
Clerked and mailed on 12/3/01

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. Friday 12/3/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Title V Air Operation Permit Revision
DRAFT Permit No.: 0310045-008-AV

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Duval County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue a Title V Air Operation Permit Revision to Jacksonville Electric Authority for the Northside Generating Station/St. Johns River Power Park located at 4377 Heckscher Drive, Jacksonville, Duval County. The purpose of the revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 simple cycle combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. The applicant's name and address are: Mr. Walter P. Bussells, CEO and Managing Director, Jacksonville Electric Authority, 21 West Church Street, Jacksonville, Florida 32202.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the 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 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.

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 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/488-9730; Fax: 850/487-4938). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address and telephone number of the petitioner; name address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how petitioner's substantial rights will be affected by the agency determination;

(c) A statement of how and when the petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so state;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle petitioner to relief; and,

(f) A demand for relief.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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.

Mediation is not available for this proceeding.

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: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

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

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

<u>Affected Local Program:</u>
City of Jacksonville
Regulatory and Environmental Services Department
Air & Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111
Telephone: 904/630-3484
Fax: 904/630-3638

The complete project file includes the DRAFT Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Scott M. Sheplak, P.E., at the above address, or call 850/921-9532, for additional information.

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park
Facility ID No.: 0310045
Duval County

Title V Air Operation Permit Revision
DRAFT Permit No.: 0310045-008-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
City of Jacksonville
Regulatory and Environmental Services Department
Air and Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111
Telephone: 904/630-3484
Fax: 904/630-3638

Title V Air Operation Permit Revision
DRAFT Permit No.: 0310045-008-AV

Table of Contents

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

Permittee:
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

DRAFT Permit No.: 0310045-008-AV
Facility ID No.: 0310045
SIC No.: 49; 4911
Project: Title V Air Operation Permit Revision

This permit revision is for the authorization to operate direct water spray fogging devices ahead of the compressors on four identical and existing General Electric Model MS 7000 simple cycle combustion turbines (Nos. 3 thru 6) located at the Jacksonville Electric Authority's Northside Generating Station. This facility is located at 4377 Heckshire Drive, Jacksonville, Duval County; UTM Coordinates: Zone 17, 446.90 km East and 3359.150 km North; Latitude: 30° 21' 52" North and Longitude: 81° 37' 25" West.

This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-4, 62-210, 62-213 and 62-214, F.A.C.; the City of Jacksonville Ordinance Code (JOC), Title X, Chapter 376; and, the Jacksonville Environmental Protection Board (JEPB) Rule 2, Parts I thru VII and Parts IX thru XII. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-3, TITLE V CONDITIONS (version dated 4/30/98)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (dated 10/07/96)
FIGURE 1 - SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEMS PERFORMANCE REPORT (40 CFR 60, July 1996)
Operation and Maintenance Plan
Alternate Sampling Procedure: ASP Number 97-B-01
Appendix 40CFR60 Subpart A - General Provisions (dated 07/23/97)
Attachment NGS: CT Heat Input Nominal Values
Attachment SJRPP: Material Handling Transfer Points
Attachment SJRPP: Protocol for Startup and Shutdown

Effective Date: January 1, 1999
Revision Effective Date: (ARMS Day 55)
Renewal Application Due Date: July 5, 2003
Expiration Date: December 31, 2003

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/sms/bm

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of five boilers, Northside Generating Station (NGS) Boilers Nos. 1, 2 and 3 **(No. 2 was placed on long-term reserve shutdown on March 1, 1984)** and St. Johns River Power Park (SJRPP) Boilers Nos. 1 and 2; four combustion turbines, NGS Nos. 3, 4, 5 and 6 (Nos. 1 and 2 are inactive); and, an auxiliary boiler, NGS No. 1. The NGS auxiliary boiler is allowed to operate when one of the main boilers is shut down or in a startup mode prior to being put on line. Emissions from the NGS Boilers Nos. 1, 2 and 3, are uncontrolled. Emissions from the auxiliary boilers and the NGS CTs Nos. 3, 4, 5 and 6, are controlled firing low sulfur fuel oil. Emissions from the SJRPP Boilers Nos. 1 and 2 are controlled with an electrostatic precipitator, a limestone scrubber, and low-NO_X burners. The SJRPP facility also includes coal, petroleum coke, limestone and flyash handling activities, of which various control devices, control strategies, and control techniques are required. Also, included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

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

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2 (on long-term reserve shutdown since 03/01/84)
-003	NGS Boiler No. 3
-004	NGS Combustion Turbine No. 1 (inactive: permit surrendered and dismantled)
-005	NGS Combustion Turbine No. 2 (inactive: permit surrendered and dismantled)
-006	NGS Combustion Turbine No. 3
-007	NGS Combustion Turbine No. 4
-008	NGS Combustion Turbine No. 5
-009	NGS Combustion Turbine No. 6
-013	NGS Auxiliary Boiler No. 1
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2
-018	SJRPP Auxiliary Boilers Nos. 1 and 2 (inactive: dismantled)
-022	SJRPP Limestone and Flyash Handling
-023	SJRPP Coal Storage Yard and Transfer Systems
-024	SJRPP Cooling Towers (2)

Unregulated Emissions Units and/or Activities
{Permitting note: For Unregulated Emissions Units and/or Activities, see Appendix U-1 (attached).}

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
Statement of Basis

These documents are on file with the permitting authority:
BACT Determinations dated 10/15/84 (NGS) and 05/07/81 (SJRPP).
Phase II SO_2 Acid Rain Application/Compliance Plan received 12/26/95.
Initial Title V Permit Application received 06/14/96.
PSD-FL-010(B) issued 10/14/96.
ORDER EXTENDING PERMIT EXPIRATION DATE dated 11/13/97.
Phase I/II NO_X Acid Rain Compliance Plan dated 12/19/97.
Initial Title V Permit issued 10/13/98, and effective 01/01/99 (0310045-001-AV).
Title V Permit Revision effective 01/10/1999 (0310045-002-AV).
Application for Title V Permit Revision received 10/05/2001.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

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

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall 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.; and, Jacksonville Environmental Protection Board (JEPB) Rule 2, Part IX]

3. **Not federally enforceable.** Odor Nuisance. Pursuant to JOC Chapter 376, any facility that causes or contributes to the emission of objectionable odors which results in the City of Jacksonville Air and Water Quality Division (AWQD) receiving and validating complaints from five (5) or more different households within a 90 day period and can be cited for objectionable odors.
[JOC Chapter 376]

4. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.; and, Part X, Rule 2.1001, JEPB]

5. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office RMP Reporting Center when, and if, such requirement becomes applicable. Any RMPs, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

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

6. 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.]

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

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

{Permitting note: There are no requirements deemed necessary and ordered by the Department at this time.}

[Rule 62-296.320(1)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

9. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: chemical or water application to unpaved roads or unpaved yard areas; paving and maintenance of roads, parking areas and plant grounds; landscaping and planting of vegetation; confining abrasive blasting where possible; and other techniques, as necessary. Also, for the solid waste disposal area, wetting agents shall be applied.
[Rule 62-296.320(4)(c)2., F.A.C.; Part X, Rule 2.1001, JEPB; and, PSD-FL-010 and PA 81-13]

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

11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

12. The permittee shall submit all compliance related notifications and reports required of this permit to the AWQD office at the following address:

City of Jacksonville
Regulatory and Environmental Services Department
Air and Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111
Telephone: 904/630-3484
Fax: 904/630-3638

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

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Operating Permits Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9099
Fax: 404/562-9095

Section III. Emissions Units.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2
-003	NGS Boiler No. 3

NGS Boiler No. 1 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 2767 MMBtu per hour when firing fuel oil; (2) 2892 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 2767 - 2892 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 250 feet. NGS Boiler No. 1 began commercial operation in 1966.

NGS Boiler No. 2 is a fossil fuel-fired steam generator with a nominal nameplate rating of 297.5 megawatts (electric). The emissions unit is permitted to fire new No. 6 residual fuel oil, natural gas, and a blend of fuel oil and natural gas. The maximum heat inputs are (1) 2341 MMBtu per hour when firing fuel oil; (2) 2352 MMBtu per hour when firing natural gas; or (3) 2341 - 2352 MMBtu per hour when firing a combination of No. 6 fuel oil and natural gas, respectively. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through a single stack of 300 feet. NGS Boiler No. 2 began commercial operation in November 1966. **NGS Boiler No. 2 was placed on long-term reserve shutdown on March 1, 1984.**

NGS Boiler No. 3 is a fossil fuel-fired steam generator with a nominal nameplate rating of 563.7 megawatts (electric). The emissions unit will be allowed to fire new No. 6 residual fuel oil, natural gas, LP gas, "on-specification" used oil, landfill gas, and a blend of fuel oil and natural gas and/or landfill gas. The maximum heat inputs are (1) 5033 MMBtu per hour when firing fuel oil; (2) 5260 MMBtu per hour when firing natural gas or natural/landfill gases; or (3) 5033 - 5260 MMBtu per hour when firing a combination of fuel oil and natural gas or natural/landfill gases, respectively. LP gas is used as the igniter fuel when natural gas is not available. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Pollutant emissions from this emissions unit are uncontrolled. The combustion gases exhaust through two stacks of 300 feet. NGS Boiler No. 3 began commercial operation in 1977.

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.702, F.A.C., Fossil Fuel Steam Generators.}

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

Essential Potential to Emit (PTE) Parameters

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

EU ID No.	MMBtu/hr Heat Input	Fuel Type
NGS Boiler No. 1	2892	Natural Gas
	2892	Landfill Gas
	2767	New No. 6 Fuel Oil
	2767	"On-specification" Used Oil
	2767-2892	Fuel Oil and Natural Gas
	2767-2892	Fuel Oil and Natural/Landfill Gases
NGS Boiler No. 2	2352	Natural Gas
	2341	New No. 6 Fuel Oil
	2341-2352	New No. 6 Fuel Oil and Natural Gas
NGS Boiler No. 3	5260	Natural Gas
	5260	Landfill Gas
	5033	New No. 6 Fuel Oil
	5033	"On-specification" Used Oil
	5033-5260	Fuel Oil and Natural Gas
	5033-5260	Fuel Oil and Natural/Landfill Gases

Note: When a blend of fuel oil and natural and/or landfill gas is fired, the heat input is prorated based on the percent heat input of each fuel.

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

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; and, AO16-194743, AO16-178094 and AO16-207528]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific conditions **A.26.** and **A.27.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels.
a. The only fuels allowed to be burned are natural gas, LP gas, landfill gas, new No. 6 fuel oil, "on-specification" used oil, and a blend of fuel oil and natural gas and/or landfill gas. "On-specification" used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures. LP gas is used as the igniter fuel when natural gas is not available.

b. The total station (NGS Boilers Nos. 1, 2 and 3, and NGS Auxiliary Boiler No. 1) residual fuel oil consumption must not exceed 1,440,000 pounds in any consecutive three (3) hour period.
[Rule 62-213.410, F.A.C.; 40 CFR 271.20(e)(3); AO16-194743, AO16-178094 and AO16-207528; AC16-85951 and BACT; and, applicant request dated June 14, 1996.]

A.4. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; and, AO16-194743, AO16-178094 and AO16-207528]

Emission Limitations and Standards

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

A.5. Visible Emissions. For Boilers Nos. 1 and 3, visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-194743 and AO16-207528]

A.6. Visible Emissions. For Boiler No. 2, visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-178094]

A.7. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C; and, Part III, Rule 2.301, JEPB]

A.8. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input , as measured by applicable compliance methods. See specific condition **A.22**.
[Rules 62-296.405(1)(b) and 62-296.702(2)(a), F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.9. 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.; and, Part III, Rule 2.301, JEPB]

A.10. Sulfur Dioxide. SO_2 emissions shall not exceed 1.98 pounds per million Btu heat input, as measured by applicable compliance methods. Any calculations or methods used to demonstrate compliance shall be based on the total heat input from all fossil fuels, including natural gas, and the sulfur from all fuels fired. See specific conditions **A.17., A.23.** and **A.24.**
[Rules 62-213.440 and 62-296.405(1)(c)1.a., F.A.C.; and, Part X, Rule 2.1001, JEPB]

A.11. Sulfur Dioxide - Sulfur Content. For Boilers Nos. 1 and 3, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 1.8 percent, by weight, if the SO_2 continuous emissions monitor system is temporarily inoperative. For Boiler No. 2, the maximum sulfur content shall not exceed 1.8%, by weight. See specific conditions **A.17.** and **A.24.**
[Rule 62-296.405(1)(e)3., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-178094 and AO16-207528]

A.12. Nitrogen Oxides (expressed as NO_2). For Boiler No. 3, nitrogen oxides shall not exceed 0.30 lb/MMBtu heat input, as measured by applicable compliance methods. See specific condition **A.18.**
[Rule 62-296.405(1)(d)1., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-207528]

A.13. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. Only "on-specification" used oil generated by the Jacksonville Electric Authority in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired in these emissions units shall not exceed 1,000,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See specific conditions **A.34., A.38.** and **A.39.**

CONSTITUENT / PROPERTY *	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

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

Excess Emissions

A.14. 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.; and, Part III, Rule 2.301, JEPB]

A.15. 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.; and, Part III, Rule 2.301, JEPB]

A.16. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

A.17. Sulfur Dioxide.
a. For Boilers Nos. 1 and 3, the permittee elected to monitor emissions using a SO_2 continuous emissions monitoring system (CEMS). This procedure is allowed because the emissions units do not have an operating flue gas desulfurization device. See specific conditions **A.10., A.11., A.23.** and **A.24.**
b. Boiler No. 2 has been on long-term reserve shutdown since March 1, 1984.
c. The CEMS shall be calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and demonstrated based on a 24-hour daily average. A Relative Accuracy Testing Audit (RATA) shall be performed no less than annually.
d. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that can be used is that which was last used to demonstrate compliance prior to the loss of the CEMS, **or** the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.
e. In the event of natural gas disruption and the emissions units have to fire 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 1.8%, by weight, or less.
[Rules 62-213.440, 62-204.800, 62-296.405(1)(c)3., and 62-296.405(1)(f)1.b., F.A.C.; and, AO16-194743 and AO16-207528]

A.18. Nitrogen Oxides. For Boiler No. 3, compliance with the nitrogen oxides (expressed as NO_2) limit of 0.30 lb/MMBtu shall be demonstrated by the following:
a. Through the use of a CEMS installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 60, Appendix F, and 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and demonstrated based on a 30-day rolling average.
b. The performance specifications, location of the monitor, data requirements, data reduction and reporting requirements shall conform with the requirements of 40 CFR 51, Appendix P, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and 40 CFR 60, Appendix B, adopted by reference in Rule 62-204.800, F.A.C.
[Rules 62-296.405(1)(e)4. and 62-296.405(1)(f), F.A.C.; Part X, Rule 2.1001, JEPB; and, 40 CFR 60 & 75]

A.19. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

A.20. Visible emissions.
a. For Boilers Nos. 1 and 3, the test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C.
b. For Boiler No. 2, the test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **A.21**.
c. The visible emissions test(s) required shall be conducted simultaneously with particulate matter testing and soot blowing and non-soot blowing operating modes.
d. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(e)1. & 5., F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-194743, AO16-178094 and AO16-207528]

A.21. 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.; and, Part XI, Rule 2.1101, JEPB]

A.22. Particulate Matter.
a. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 (with Orsat analysis) or 3A shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
[Rules 62-213.440, 62-296.405(1)(e)2. & 5., and 62-297.401, F.A.C.; Part X, Rule 2.1001, JEPB and, Part XI, Rule 2.1101, JEPB]

A.23. 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.
a. For Boilers Nos. 1 and 3, the permittee shall demonstrate compliance with the 1.98 lbs/MMBtu heat input standard by either using the above referenced EPA test methods, including if used during a RATA for the SO_2 CEMS, or, as an alternate sampling procedure authorized by permit, a sulfur analyses of the as-fired fuel oils and gaseous fuels while compliance testing for particulate matter and visible emissions. See specific conditions **A.10., A.11. and A.24.**
b. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.
c. For monitoring purposes and in lieu of fuel sampling and analysis, the permittee shall operate an SO_2 CEMs. A RATA shall be conducted at least annually in accordance with 40 CFR 75.
[Rules 62-213.440, 62-296.405(1)(e)3. & 5., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.; Part V, Rule 2.501, JEPB; Part X, Rule 2.1001, JEPB; Part XI, Rule 2.1101, JEPB; and, AO16-194743, AO16-178094 and AO16-207528]

A.24. For Boilers Nos. 1 and 3, the following fuel sampling and analysis protocol shall be used if the permittee opts to demonstrate compliance with the sulfur dioxide standard using an alternate sampling procedure authorized by permit and conducted while performing a compliance test for particulate matter and visible emissions:

a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel oil following each fuel delivery, (2) for gaseous fuels using ASTM D 1072-80, or the latest edition (the permittee can default to the maximum sulfur content guaranteed by the supplier).

b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuel oil to gas if co-fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.

c. The analyses of the No. 6 fuel oil, as received from the supplier, shall include the following:
  (1). Density (ASTM D 1298-80 or the latest edition).
  (2). Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).

d. The analyses of the gaseous fuels, as received from the supplier, shall include the following:
  (1). Density (ASTM D1137-53, ASTM D1945-64, or the latest edition).
  (2). Calorific heat value in Btu per cubic foot (ASTM D1137-53, ASTM D1945-64, ASTM D1826-77, or the latest edition).

e. Utilize the above information in a., b., c. and d. to calculate the SO_2 emission rate.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; AO16-194743, AO16-178094 and AO16-207528; and, 40 CFR 60. Appendix A]

A.25. 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.; and, Part XI, Rule 2.1101, JEPB]

A.26. 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.; and, Part XI, Rule 2.1101, JEPB]

A.27. Operating Conditions During Testing - Particulate Matter and Visible Emissions. Compliance tests for particulate matter and visible emissions during soot blowing and steady-state (non-soot blowing) operations shall be conducted at least once, annually, if liquid fuel is fired for more than 400 hours. All visible emissions tests shall be conducted concurrently with the particulate matter emissions tests. Testing shall be conducted as follows:
a. 100% Fuel Oil Firing.: Particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed on each emissions unit while firing fuel oil containing a sulfur content equal to or less than 1.8%, by weight, except that such test shall not be required to be performed during any federal fiscal year that testing is performed in accordance with specific condition **A.27.b**.
b. Co-firing Fuel Oil with Gases.: If fuel oil containing a sulfur content greater than 1.8%, by weight, is co-fired with gases (i.e., natural gas, landfill gas, LP gas), then particulate matter and visible emissions tests during soot blowing and steady-state operations shall be performed as soon as practicable, but in no event more than 60 days from the day of first firing the higher percent sulfur fuel oil, while co-firing such fuel oil with the proportion of gas required to maintain SO_2 emissions between 90 to 100% of the SO_2 emissions limitation (1.62 to 1.98 lbs/MMBtu heat input, respectively). Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If fuel oil is co-fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests for particulate matter and visible emissions, then additional particulate matter and visible emissions tests shall be performed as described above and as soon as practicable, but in no event more than 60 days from the day of first firing the higher sulfur percent fuel oil. Following successful completion of such particulate matter and visible emissions testing, further particulate matter and visible emissions testing shall not be required during the remaining federal fiscal year unless fuel oil is fired containing a sulfur content greater than 0.20%, by weight, above the fuel oil sulfur content percent, by weight, that was fired during the most recent co-firing compliance tests. If any additional particulate matter and visible emissions tests are imposed after completion of any required annual compliance tests, then the frequency testing base date shall be reset to 12-months after the date of completion of the last tests.
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.28. 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.; and, Part XI, Rule 2.1101, JEPB]

A.29. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

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

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

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.30. 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, and Part XI, Rule 2.1101, JEPB.
[Rule 62-297.310(6), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.31. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

(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.; Part XI, Rule 2.1101, JEPB; AO16-194743, AO16-178094 and AO16-207528; and, SIP approved]

A.32. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or

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

c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

A.33. 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.; Part XI, Rule 2.1101, JEPB; and, ASP Number 97-B-01.]

A.34. Compliance with the "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. See specific conditions **A.13., A.38.** and **A.39**.
[Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Record keeping and Reporting Requirements

A.35. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

A.36. For each calendar quarter, submit to the AWQD a written report of emissions in excess of emission limiting standards, as set forth in Rule 62-296.405(1), F.A.C., and any continuous emissions monitoring system outages. The nature and cause of the excess emissions shall be explained. The report shall be submitted within 30 calendar days following the last day of the quarterly period. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.; Part X, Rule 2.1001, JEPB; and, AO16-207528]

A.37. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD 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 AWQD 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.; Part XI, Rule 2.1101, JEPB; and, AO16-214193, AO16-214194 and AO16-214195]

A.38. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **A.13., A.34.** and **A.39.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.39. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Boilers Nos. 1 and 3 during the calendar year. See specific conditions **A.13., A.34.** and **A.38.**
[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.40. When any of the NGS boilers, Nos. 1, 2 and 3, are shut down, it shall be recorded in the boiler's operating log book.
[Rule 62-213.440, F.A.C.; and, AC16-85951]

A.41. When electrical power demand requires all three main NGS boilers to be on line, the total station residual (No. 6) fuel oil consumption shall be recorded for each four-hour period whenever the NGS auxiliary steam generator (boiler) is operating. The recorded fuel consumption data shall be retained for at least five (5) years.
[Rule 62-213.440, F.A.C.; and, AC16-85951]

A.42. Fuel Consumption Records. The owner or operator shall create and maintain for each emissions unit hourly records of the amount of each fuel fired, the ratio of fuel oil to gas if co-fired, and the heating value and sulfur content, percent by weight, of each fuel fired. These records must be of sufficient detail to be able to identify when additional particulate matter and visible emissions testing is required pursuant to specific condition **A.27.b.**, and, when applicable, demonstrate compliance with the requirements of specific condition **A.24.e**.
[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

Miscellaneous

A.43. For Boilers Nos. 1, 2 and 3, an Operation and Maintenance Plan is attached and a part of this permit pursuant to Rule 62-296.700(6), F.A.C. All activities shall be performed as scheduled and recorded data made available to the AWQD upon request. Records shall be maintained on file for a minimum of five (5) years.
[Rule 62-296.700(6), F.A.C.; and, Part X, Rule 2.1001, JEPB]

Section III. Emissions Units.

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-014	Northside Generating Station (NGS) Auxiliary Boiler No. 1

The NGS Auxiliary Boiler No. 1 is steam generator that is allowed to fire natural gas, LP gas, new No. 2 distillate or new No. 6 residual fuel oils, and a blend of new fuel oil(s) with internally generated waste oil that does not contain any polychlorinated biphenyls (PCBs). The maximum fuel oil sulfur content is 1.8%, by weight (BACT dated October 15, 1984). Emissions from this boiler are uncontrolled. The NGS Auxiliary Boiler No. 1 was authorized construction on October 15, 1984. This emissions unit can only be operated when one of the main NGS boilers (No. 1, 2 or 3) is either shut down or is in the startup mode of operation prior to being on line ***or*** when electrical power demand requires that all three main boilers (NGS Nos. 1, 2 and 3) and the auxiliary boiler (NGS No. 1) to be on line.

{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, which includes BACT (dated October 15, 1984).}

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

Essential Potential to Emit (PTE) Parameters

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

EU ID No.	**MMBtu/hr Heat Input**	**Fuel Type**
Aux. Boiler No. 1	123.5	Natural Gas
	123.5	LP Gas
	118.0	New No. 2 Fuel Oil
	116.5	New No. 6 Fuel Oil
	116.5-118.0	New Fuel Oil and On-site Generated Waste Oil

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

[AC16-85951; and, application received June 14, 1996.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.16.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels.
a. The only fuels allowed to be fired are natural gas, LP gas, new No. 2 distillate or new No. 6 residual fuel oils, or a blend of new fuel oil(s) with "internally generated waste oil". The "internally generated waste oil" includes "on-specification" used oil, and excludes any PCB containing material from being fired in this emissions unit.
b. The total station (NGS's Boilers Nos. 1, 2 and 3, and Auxiliary Boiler No. 1) residual (No. 6) fuel oil consumption must not exceed 1,440,000 pounds in any consecutive three (3) hour period.
[Rule 62-213.410, F.A.C.; and, AC16-85951 and BACT]

B.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8760 hours/year, but only when at least one of the main steam generating boilers (NGS Boiler No. 1, 2, or 3) is either shut down or in the startup mode of operation prior to being on line ***or*** when electrical power demand requires that all three main boilers (NGS Nos. 1, 2 and 3) and the auxiliary boiler (NGS No. 1) be on line. See specific conditions **B.3.b.**, **B.24.** and **B.25.**
[AC16-85951]

Emission Limitations and Standards

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

B.5. Visible Emissions. Visible emissions shall not exceed 15 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[AC16-85951 and BACT]

B.6. Particulate Matter. Particulate matter emissions shall be controlled by the firing of natural gas and/or low sulfur content liquid fuel oil.
[Rule 62-296.406(2), F.A.C.; Part X, Rule 2.1001, JEPB; and, BACT]

B.7. Sulfur Dioxide - Sulfur Content. The maximum sulfur content of the new No. 2 distillate fuel oil, new No. 6 residual fuel oil, or blended fuel oil is 1.8 percent, by weight. See specific conditions **B.14.** and **B.15.**
[Rule 62-296.406(3), F.A.C.; and, AC16-85951 and BACT]

B.8. Internally Generated Waste Oil" ("On-specification" Used Oil). The burning of "internally generated waste oil", which includes "on-specification" used oil, is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. "Internally generated waste oil" is defined as: 1) automotive waste oils consisting of crankcase drainage, transmission fluids, gear lubricants, hydraulic oils, and minor amounts of kerosene and other solvents used in servicing equipment; 2) industrial waste oils used in metal working, lubrication of industrial equipment, hydraulic and circulating systems, diesel engines and turbine lubrication; and, 3) waste oils which have been used in transformers and heat transfer equipment that does not contain any PCBs.

b. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below, except for PCBs. By permit, no (0.00%, by weight) PCBs are not allowed to be fired in this emissions unit. Used oil that does not meet all of the following specifications (normally, PCBs are limited to "less than 50 ppm") is considered "off-specification" used oil and shall not be fired in this emissions unit. See specific conditions **B.20.**, **B.26.** and **B.27**.

CONSTITUENT / PROPERTY*	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	none

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
[Rule 62-213.440, F.A.C.; AC16-85951 and BACT; and, 40 CFR 279.11]

Excess Emissions

B.9. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess 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.; and, Part III, Rule 2.301, JEPB]

B.10. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

B.11. 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.; and, Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

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

B.12. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. See specific condition **B.13.**
[Rules 62-213.440 and 62-297.401, F.A.C.; Part XI, Rule 2.1101, JEPB; and, AC16-85951]

B.13. 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.; and, Part XI, Rule 2.1101, JEPB]

B.14. 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. See specific conditions **B.7.** and **B.15.**
[Rules 62-213.440 and 62-296.406(3), F.A.C.; and, AC16-85951]

B.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. See specific conditions **B.7.** and **B.14.**
[Rules 62-213.440, 62-296.406(3) and 62-297.440, F.A.C.; and, AC16-85951]

B.16. Operating Rate During Testing. Testing of emissions shall be conducted with the 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.; Part XI, Rule 2.1101, JEPB; and, AC16-85951]

B.17. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.18. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or
b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and,
   c. Each NESHAP pollutant, if there is an applicable emission standard.
9. The owner or operator shall notify the AWQD, at least **14** days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; AC16-85951; and, SIP approved]

B.19. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.20. Compliance with the "internally generated waste oil" - "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. See specific conditions **B.8., B.26.** and **B.27**.
[Rules 62-4.070 and 62-213.440, F.A.C; and, 40 CFR 279]

Record keeping and Reporting Requirements

B.21. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

B.22. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

B.23. The permittee shall submit all fuel oil analyses (every fuel oil delivery needs a fuel analysis report) and the visible emissions test, if one is required, to the AWQD annually. If fuel oil is being fired during a visible emissions test, then a sample of fuel oil shall be extracted during the test and analyzed; and, the analysis shall be submitted with the visible emissions test result to AWQD pursuant to Rule 62-297.310(8), F.A.C. See specific condition **B.22.**
[AC16-85951]

B.24. When any of the NGS boilers, Nos. 1, 2 and 3, are shut down, it shall be recorded in the boiler's operating log book.
[Rule 62-213.440, F.A.C.; and, AC16-85951]

B.25. When electrical power demand requires all three main NGS boilers to be on line, the total station residual (No. 6) fuel oil consumption shall be recorded for each four-hour period whenever the NGS auxiliary steam generator (boiler) is operating. The recorded fuel consumption data shall be retained for at least five (5) years.
[Rule 62-213.440, F.A.C.; and, AC16-85951]

B.26. Records shall be kept of each delivery of "internally generated waste oil" - "on-specification" used oil with a statement of the origin of the waste/used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "internally generated waste oil" - "on-specification" used oil fired in this emissions unit. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **B.8.**, **B.20.** and **B.27.**
[Rule 62-213.440, F.A.C.; AC16-85951; and, 40 CFR 279.61 and 761.20(e)]

B.27. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "internally generated waste oil" - "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in the (NGS) auxiliary boiler during the calendar year. See specific conditions **B.8.**, **B.20.** and **B.26.**
[Rule 62-213.440(1)(b)2.b., F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-006	Combustion Turbine No. 3
-007	Combustion Turbine No. 4
-008	Combustion Turbine No. 5
-009	Combustion Turbine No. 6

Emissions units numbers 003, 004, 005 and 006 are combustion turbines (CTs) manufactured by General Electric (Model MS 7000) and are designated as CTs No. 3, No. 4, No. 5 and No. 6, respectively. Each CT has a maximum heat input from new No. 2 distillate fuel oil of 901.0 MMBtu (LHV: lower heating value). The No. 2 fuel oil has a maximum sulfur content of 0.5%, by weight. These CTs are used as peaking units during peak demand times, during emergencies, and during controls testing, to run a nominal 56.2 MW generator (each). Emissions from the CTs are uncontrolled. Direct water spray fogger devices were installed in the inlet ducts of each CT to provide adiabatic inlet air cooling that increases turbine output and decreases heat rate. A group of exhaust stacks serve the CTs. CT No. 3 began commercial service in February 1975, No. 4 in January 1975, No. 5 in February 1974, and, No. 6 in December 1974.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

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:

EU ID No.	MMBtu/hr Heat Input	Fuel Type
3	901.0 (LHV)	New No. 2 Fuel Oil
4	901.0 (LHV)	New No. 2 Fuel Oil
5	901.0 (LHV)	New No. 2 Fuel Oil
6	901.0 (LHV)	New No. 2 Fuel Oil

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

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO16-173886]

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **C.13**.
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation - Fuels. Only new No. 2 distillate fuel oil shall be fired in the combustion turbines.
[Rule 62-213.410(1), F.A.C.; and, AO16-173886]

C.4. Hours of Operation.
a. These CTs may operate continuously, i.e., 8,760 hours/year.
b. Each CT shall not exceed 399 hrs/yr operation while using foggers.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AO16-173886; and, 0310045-006-AC]

Emission Limitations and Standards

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

C.5. Visible Emissions. Visible emissions from each combustion turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO16-173886]

C.6. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 distillate fuel oil shall not exceed 0.5 percent, by weight. See specific conditions **C.9.** and **C.12**.
[Requested in initial Title V permit application dated June 14, 1996; and, AO16-173886]

Excess Emissions

C.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.8. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

C.9. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery. See specific conditions **C.6.** and **C.12**.
[Rule 62-213.440, F.A.C.]

C.10. 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.; and, Part XI, Rule 2.1101, JEPB]

__Test Methods and Procedures__

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

C.11. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.12. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition.
[Rules 62-213.440 and 62-297.440, F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.13. <u>Operating Rate During Testing</u>. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: Attached (see "Attachment NGS: CT Heat Input Nominal Values") is a chart of the "Base Load MW" vs "Temperature" to aid in defining "full load" for visible emissions testing purposes, since the manufacturer's curves are not available. The heat input numbers are only nominal values.}

[Rules 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.14. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When EPA Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or
b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
a. Visible emissions, if there is an applicable standard;
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

C.16. Visible Emissions Testing - Biennial. By this permit, biennial (odd years) emissions compliance testing for visible emissions is required for each emissions unit, but is not required for those emissions units burning No. 2 fuel oil for less than 400 hours during the previous even year or the current odd year in question.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.; Part XI, Rule 2.1101, JEPB; and, AO16-173880]

Recordkeeping and Reporting Requirements

C.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

C.18. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

C.19. Records of No. 2 fuel oil consumption shall be maintained and made available to AWQD upon request.
[Rule 62-213.440, F.A.C.; and, AO16-173886]

C.20. Foggers. A log book shall be maintained to show when each CT is using a fogger device and shall provide the beginning and ending times (hour and minute) of its use. See Specific Condition **C.4.b.**
[Rule 62-4.070(3), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

SJRPP Boilers Nos. 1 and 2 are fossil fuel-fired steam generators, each having a nominal nameplate rating of 679.6 megawatts (electric). The emissions units will be allowed to fire pulverized coal, a blend of petroleum coke and coal, new No. 2 distillate fuel oil (startup and low-load operation), and "on-specification" used oil. The maximum heat input to each emissions unit is 6,144 million Btu per hour. SJRPP Boilers Nos. 1 and 2 are dry bottom wall-fired boilers and will use an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulfurization (FGD) unit to control sulfur dioxide, low NO_X burners and low excess-air firing to control nitrogen oxides, and good combustion to control carbon monoxide. Each boiler exhausts through its own stack (640 feet above grade). SJRPP Boiler No. 1 began commercial operation in December 1986. SJRPP Boiler No. 2 began commercial operation in March 1988.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II and Phase I; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration [PSD; PSD-FL-010; PSD-FL-010(A & B)]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981.}

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

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

Essential Potential to Emit (PTE) Parameters

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

Emissions Unit No.	MMBtu/hr Heat Input
-016	6,144
-017	6,144

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

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; PSD-FL-010; Part III, Rule 2.301, JEPB; and, PA 81-13]

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.46.**
[Rule 62-297.310(2), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.3. Methods of Operation.
a. The only fuels allowed to be fired are coal, a coal blend with a maximum of 20 percent petroleum coke (by weight), new No. 2 distillate fuel oil, and "on-specification" used oil.
b. The new No. 2 fuel oil shall be used for startup and low load operation.
c. The maximum weight of petroleum coke burned shall not exceed 100,000 pounds per hour.
d. "On-specification" used oil will be generally fired as a blend with the No. 2 fuel oil. "On-specification" used oil containing PCBs above the detectable level of 2 ppm shall not be used for startup or shutdown. "On-specification" used oil containing PCBs between 2 and 49 ppm can only be fired when the emissions unit is at normal operating temperatures.
e. Either coal, a blend of coal and petroleum coke, or fuel oil shall not be fired in the emissions units unless both electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 CFR 60, Subpart Da.
f. No fraction of the flue gas shall be allowed to bypass the limestone flue gas desulfurization (FGD) system to reheat the gasses exiting from the FGD system, if the bypass will cause overall SO_2 removal efficiency less than 90 percent or as otherwise provided in 40 CFR 60, Subpart Da. The percentage and amount of flue gas bypassing the FGD system shall be documented.
g. The permittee shall not operate its Southside, Northside, or Kennedy Generating Station in such a manner as to cause violation of ambient air quality standards for SO_2 when SJRPP is operating.
[Rule 62-213.410, F.A.C.; PSD-FL-010; PA 81-13; PSD-FL-010(A & B); 40 CFR 761.20(e); and, requested by the applicant in the initial Title V permit application received June 14, 1996]

D.4. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; PSD-FL-010; and, PA 81-13]

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.}

D.5. Revised Table 6, PSD-FL-010, is incorporated by reference (attached) for emissions units 1 and 2.

D.6. Particulate Matter. No owner or operator shall cause to be discharged into the atmosphere from any emissions unit any gases which contain particulate matter in excess of:
(1) 0.03 lb/million Btu heat input derived from the combustion of solid or liquid fuels (coal, a blend of coal and petroleum coke, or fuel oil);
(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel (coal or a blend of coal and petroleum coke), and
(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.
(4) Particulate matter emissions shall be controlled with an electrostatic precipitator.
[40 CFR 60.42a(a)(1), (2) & (3); PSD-FL-010 and BACT; PA 81-13; and, PSD-FL-010(A & B)]

D.7. Ash Content.
a. The maximum ash content of the coal is 18%, by weight.
b. The maximum ash content of the No. 2 fuel oil is 0.01%, by weight.
[PSD-FL-010; and, PA 81-13]

D.8. Visible Emissions. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6 minute average), except for one 6-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42a(b); and, PA 81-13]

D.9. Sulfur Dioxide - Coal Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain sulfur dioxide in excess of:
(1) 1.20 lb/million Btu heat input, maximum two-hour average, and 0.76 lb/MMBtu heat input (90% reduction of the potential combustion concentration), 30-day rolling average; or
(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 0.60 lb/million Btu heat input.
(3) 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 0.20 lb/million Btu heat input.
(4) SO_2 emissions shall be controlled with a lime/limestone flue gas desulfurization system on each boiler.
[40 CFR 60.43a(a)(1), (2) & (3); PSD-FL-010 and BACT; and, PA 81-13]

D.10. Sulfur Dioxide - Coal and Petroleum Coke Blends.
a. When coals with a sulfur content less than or equal to 2.00%, by weight, are co-fired with petroleum coke, the SO_2 emissions shall not exceed 0.55 lb/MMBtu heat input and a minimum of 76% reduction shall be achieved in the flue gas desulfurization system.
b. When coals with a sulfur content between 2.00% and 3.63%, by weight, are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

$$SO_2 \text{ (lb/MMBtu)} = (0.2 \times C/100) + 0.4$$

where: C = percent of coal co-fired on a heat input basis.

Please note: C is on a heat input basis and not on a weight input basis, so appropriate conversions should be used.

c. When coals with a sulfur content greater than 3.63%, by weight, are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

$$SO_2 \text{ (lb/MMBtu)} = (0.1653 \times C \times S - 0.4 \times C + 40) \times 1/100$$

where: C = percent of coal co-fired on a heat input basis; and,
S = weight percent sulfur in coal.

d. The maximum SO_2 emissions rate when co-firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu heat input.
e. Compliance with the SO_2 emissions limit shall be based on a 30-day rolling average for those days when petroleum coke is fired. Any use of petroleum coke during a 24-hour period shall be considered 1 day of the 30-day rolling average. The 30-day rolling average shall be calculated according to the Standards of Performance for New Stationary Sources (NSPS) codified in 40 CFR 60, Subpart Da, except as noted above.
[PSD-FL-010(A & B)]

D.11. Sulfur Dioxide - Liquid Fuel Only. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility which combusts liquid fuel any gases which contain sulfur dioxide in excess of:
(1) 340 ng/J (0.80 lb/million Btu) heat input and 90 percent reduction, or
(2) 100 percent of the potential combustion concentration (zero percent reduction), when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.
[40 CFR 60.43a(b)(1) & (2)]

D.12. Sulfur Dioxide. Compliance with the emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis.
[40 CFR 60.43a(g); PSD-FL-010; and, PA 81-13]

D.13. Sulfur Dioxide - Sulfur Content.
a. The maximum coal sulfur content shall not exceed 4.0 percent, by weight.
b. The maximum sulfur content of the coal - petroleum coke blend shall not exceed 4.0 percent, by weight.
c. The maximum sulfur content of the No. 2 fuel oil is 0.76%, by weight.
[PSD-FL-010; PA 81-13; and, PSD-FL-010(A & B)]

D.14. Sulfur Dioxide. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formulas:
(1) If emissions of SO_2 to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input:

$PS_{SO2} = (340X + 520Y)/100$ and
$\%P_S = 10$

(2) If emissions of SO_2 to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$PS_{SO2} = (340X + 520Y)/100$ and
$\%P_S = (10X + 30Y)/100$

where:
PS_{SO2} = the prorated standard for sulfur dioxide when combusting fuel oil and coal (or a blend of coal and petroleum coke) simultaneously (ng/J heat input).
$\%P_S$ = percentage of potential SO_2 emissions allowed.
X = the percentage of total heat input derived from the combustion of fuel oil (excluding solid-derived fuels).
Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke (including solid-derived fuels).
[40 CFR 60.43a(h)(1) & (2)]

D.15. Nitrogen Oxides. No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.
(1) NO_X emissions limits.
  a. Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input;
  b. Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input.
(2) NO_X reduction requirement.
  a. Solid fuels: 65 percent reduction of potential combustion concentration;
  b. Liquid fuels: 30 percent reduction of potential combustion concentration.
[40 CFR 60.44a(a)(1) & (2)]

D.16. Nitrogen Oxides. When fuel oil and coal (or a blend of coal and petroleum coke) are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$PS_{NOX} = (130X + 260Y)/100$

where:
PS_{NOX} is the prorated standard for nitrogen oxides when combusting coal (or a blend of coal and petroleum coke) and fuel oil simultaneously (ng/J heat input).
X = the percentage of total heat input derived from the combustion of fuel oil.
Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke.
[40 CFR 60.44a(c); and, PSD-FL-010]

D.17. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. Only "on-specification" used oil generated by the Jacksonville Electric Authority in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired in these emissions units shall not exceed 1,000,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See specific conditions **D.44.**, **D.63.**, **D.64.** and **D.66.**

CONSTITUENT / PROPERTY *	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

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

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.}

D.18. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. See Attachment SJRPP: Protocol for Startup and Shutdown.
[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

{Permitting note: Once a written agreement between JEA and AWQD has been acquired approving a "Protocol for Startup and Shutdown", the protocol is automatically incorporated by reference and is a part of the permit. The protocol shall be used where applicable and where there is/are conflict with the rule.}

D.19. 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.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

D.20. 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.; and, Part XI, Rule 2.1001, JEPB]

Compliance Provisions

D.21. Compliance with the particulate matter emission limitation under 40 CFR 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under 40 CFR 60.42a(a)(2) and (3).
[40 CFR 60.46a(a)]

D.22. Compliance with the nitrogen oxides emission limitation under 40 CFR 60.44a(a)(1) constitutes compliance with the percent reduction requirements under 40 CFR 60.44a(a)(2).
[40 CFR 60.46a(b)]

D.23. The particulate matter emission standards under 40 CFR 60.42a and the nitrogen oxide standards under 40 CFR 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under 40 CFR 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under 40 CFR 60.46a(d) are implemented.
[40 CFR 60.46a(c)]

D.24. During emergency conditions in the principle company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:
(1) Operating all operable flue gas desulfurization modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation.
[40 CFR 60.46a(d)(1) & (2)]

D.25. Compliance with the sulfur dioxide emission limitations and the percentage reduction requirements under 40 CFR 60.43a and the nitrogen oxides emissions limitations under 40 CFR 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.
[40 CFR 60.46a(e)]

D.26. Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (NO_X only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emissions rates for the 30 successive boiler operating days.
[40 CFR 60.46a(g)]

D.27. If the owner or operator has not obtained the minimum quantity of emission data as required under 40 CFR 60.47a, compliance of the affected facility with the emission requirements under 40 CFR 60.43a and 60.44a for the day on which the 30-day period ends may be determined by the Administrator following the applicable procedures in section 7 of Method 19.
[40 CFR 60.46a(h)]

Continuous Monitoring Requirements

D.28. Opacity. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharges to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).
[40 CFR 60.47a(a)]

D.29. Sulfur Dioxide. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:
(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
[40 CFR 60.47a(b)(1)]

D.30. Nitrogen Oxides. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.
[40 CFR 60.47a(c)]

D.31. The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.
[40 CFR 60.47a(d)]

D.32. The continuous monitoring systems are operated and data recorded during all periods of operation at the affected facility including periods of startup, shutdown, malfunction, or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.
[40 CFR 60.47a(e)]

D.33. The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR 60.47a(h).
[40 CFR 60.47a(f)]

D.34. The 1-hour averages required under 40 CFR 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under 40 CFR 60.46a. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages.
[40 CFR 60.47a(g)]

D.35. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in 40 CFR 60.47a(f), the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods are given in 40 CFR 60.47a(j).
(1) Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
(2) Method 7 shall be used to determine the NO_X concentration at the same location as the NO_X monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million Btu) heat input.
[40 CFR 60.47a(h)(1), (2), (3) & (4)]

D.36. The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d). Acceptable alternative methods and procedures are given in 40 CFR 60.47a(j).
(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_X concentrations.
(2) SO_2 or NO_X (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of 40 CFR 60.
(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides firing solid fuel is 1,000 ppm.
(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.
[40 CFR 60.47a(i)(1), (2), (3), & (5)]

D.37. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.47a.
(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under 40 CFR 60.47a(i), the conditions under 40 CFR 60.46(d)(1) apply (see specific condition **D.73.**); these conditions do not apply under 40 CFR 60.47a(h).
(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time is 1 hour.
(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.
(4) For Method 3B, Method 3A may be used.
[40 CFR 60.47a(j)]

<u>Test Methods and Procedures</u>

{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.}

D.38. In conducting performance tests, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in 40 CFR 60.48a, except as provided in 40 CFR 60.8(b). 40 CFR 60.8(f) does not apply to this section for SO_2 and NO_X. Acceptable alternative methods are given in 40 CFR 60.48a(e).
[40 CFR 60.48a(a)]

D.39. Particulate Matter. The owner or operator shall determine compliance with the particulate matter standard as follows

(1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same transverse points as, the particulate run. If the particulate run has more than 12 transverse points, the O_2 transverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 transverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each transverse point.

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

[40 CFR 60.48a(b)(1), (2) & (3)]

D.40. Sulfur Dioxide. The owner or operator shall determine compliance with the sulfur dioxide standards as follows:

(1) The percent of potential SO_2 emissions ($\%P_S$) to the atmosphere shall be computed using the following equation:

$$\%P_S = [(100 - \%R_F)(100 - \%R_S)]/100$$

where:

$\%P_S$ = percent of potential SO_2 emissions, percent.
$\%R_F$ = percent reduction from fuel pretreatment, percent.
$\%R_S$ = percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction ($\%R_F$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_S$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 consecutive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in 40 CFR 60.47a(b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

[40 CFR 60.48a(c)(1), (2), (3), (4) & (5)]

D.41. Nitrogen Oxides. The owner or operator shall determine compliance with the NO_X standard as follows:
(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_X.
(2) The continuous monitoring system in 40 CFR 60.47a(c) and (d) shall be used to determine the concentrations of NO_X and CO_2 or O_2.
[40 CFR 60.48a(d)(1) & (2)]

D.42. The owner or operator may use the following as alternatives to the reference methods and procedures specified in 40 CFR 60.48a:
(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed the average temperature of 160 °C (320 °F). Procedures 2.1 and 2.3 of Method 5B in 40 CFR 60, Appendix A may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.
(2) The F_C factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of 40 CFR 60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.
[40 CFR 60.48a(e)(1) & (2)]

D.43. Compliance with the "on-specification" used oil requirements will be determined as follows:
(a) Analysis of a sample collected from each batch delivered for firing; or,
(b) The new batch delivery is from a collection site that has an acceptable analysis already on file with the facility and the analytical results are assumed by the facility for the batch.
(c) For quantification purposes, the highest concentration of each constituent as determined by any analysis is assumed to be the concentration of the constituent of the blended used oil.
See specific conditions **D.17., D.64., D.65.** and **D.66.**
[Rules 62-4.070 and 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279]

D.44. If the permittee wants the CEMs RATA tests for SO_2 and NO_X to be considered as formal compliance tests, then the permittee must satisfy all of the requirements (i.e., prior notification, submittal requirements, etc.) of Rule 62-297.310, F.A.C.
[Rules 62-297.310(7) and 62-213.440, F.A.C.]

D.45. 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.; and, Part XI, Rule 2.1001, JEPB]

D.46. Operating Rate During Testing. Testing of emissions shall be conducted with the 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.; and, Part XI, Rule 2.1001, JEPB]

D.47. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.48. 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:
a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.
(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.; and, Part XI, Rule 2.1001, JEPB]

D.49. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.; and, Part XI, Rule 2.1001, JEPB]

D.50. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the AWQD, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

(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.; Part XI, Rule 2.1101, JEPB; PA 81-13; and, SIP approved]

D.51. Stack tests for particulate matter, nitrogen oxides, sulfur dioxide, and visible emissions shall be performed annually. See specific condition **D.44**.
[PA 81-13]

Recordkeeping and Reporting Requirements

D.52. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.
[40 CFR 60.49a(a)]

D.53. For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.
(1) Calendar date.
(2) The average sulfur dioxide and nitrogen oxides emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standards; and, description of corrective actions taken.
(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and, description of corrective actions taken.
(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_X only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data other than startup, shutdown, malfunction, or emergency conditions.
(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
(7) Identification of the times when hourly averages have been obtained based on manual sampling methods.
(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.
[40 CFR 60.49a(b)(1), (2), (3), (4), (5), (6), (7), (8) & (9)]

D.54. If the required quantity of emission data as required by 40 CFR 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR 60.46a(h) is reported to the Administrator for that 30-day period:
(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.
(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.
(3) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.
(4) The applicable potential combustion concentration.
(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.
[40 CFR 60.49a(c)(1), (2), (3), (4) & (5)]

D.55. If any standards under 40 CFR 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:
(1) Indicating if emergency conditions existed and requirements under 40 CFR 60.46a(d) were met during each period, and
(2) Listing the following information:
 (i) Time periods the emergency condition existed;
 (ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;
 (iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;
 (iv) Percent reduction in emissions achieved;
 (v) Atmospheric emission rate (ng/J) of the pollutant discharged; and
 (vi) Actions taken to correct control system malfunction.
[40 CFR 60.49a(d)(1) & (2)]

D.56. If fuel pretreatment credit toward the sulfur dioxide emission standard under 40 CFR 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:
(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of 40 CFR 60.48a and Method 19 (appendix A); and
(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.
[40 CFR 60.49a(e)(1) & (2)]

D.57. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and the affected facility during periods of data unavailability are to be compared with operation of the control system and the affected facility before and following the period of data unavailability.
[40 CFR 60.49a(f)]

D.58. The owner or operator of the affected facility shall submit a signed statement indicating whether:
(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
(4) Compliance with the standards has or has not been achieved during the reporting period.
[40 CFR 60.49a(g)(1), (2), (3) & (4)]

D.59. For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.
[40 CFR 60.49a(h)]

D.60. The owner or operator of an affected facility shall submit the written reports required under 40 CFR 60.49(a) and 40 CFR 60, Subpart A, to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.
[40 CFR 60.49a(i)]

D.61. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

D.62. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD 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 AWQD 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.

[Rule 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB]

D.63. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units; or, hourly if fired unblended. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See specific conditions **D.17., D.44., D.64.** and **D.65.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; Part V, Rule 2.501, JEPB; and, 40 CFR 279.61 and 761.20(e)]

D.64. The permittee shall include in the "Annual Operating Report (AOR) for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Boilers Nos. 1 and 2 and the auxiliary boilers during the calendar year. See specific conditions **D.17., D.44., D.63.** and **D.65**.
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, Part V, Rule 2.501, JEPB]

D.65. Fuel Consumption Records. The owner or operator shall maintain, for each emissions unit, a daily log of the amounts and types of fuels fired and copies of fuel analyses containing information on the sulfur and ash content, percent by weight, and heating values. See specific conditions **D.17., D.44., D.63.** and **D.64**.
[Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

D.66. Reporting and Recordkeeping. Documentation verifying that the coal and petroleum coke fuel blends combusted in Boilers Nos. 1 and 2 have not exceeded the 20 percent maximum petroleum coke by weight limit shall be maintained and made available upon request by the Department or AWQD.
[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB]

D.67. Reporting and Recordkeeping. Stack monitoring, fuel usage and fuel analysis data shall be reported to the AWQD on a quarterly basis in accordance with 40 CFR 60.7.
[PA 81-13]

D.68. Nitrogen Oxides and Particulate Matter. The permittee shall maintain and submit to the Department and AWQD, on an annual basis for a period of five years from the date each emissions unit begins co-firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in a significant emission increases of nitrogen oxides and particulate matter.
[Rule 62-213.440, F.A.C.; and, Part V, Rule 2.501, JEPB; and, PSD-FL-010(A) & (B)]

D.69. Carbon Monoxide. The permittee shall maintain and submit to the Department and AWQD, on a semiannual basis for a period of two years from the date each emissions unit begins co-firing petroleum coke, and then on an annual basis (if the first two years of data show no significant increase in carbon monoxide emissions) for an additional three years, information demonstrating that the operational changes did not result in a significant emissions increase of carbon monoxide. The carbon monoxide emissions shall be based on test results using EPA Method 10. Additionally, quarterly continuous emissions monitoring data for carbon monoxide emissions shall be submitted to the Department and AWQD for a period of two years to show the range of emissions experienced during each quarter.
[Rule 62-210.200(12)(d), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010(A) & (B)]

D.70. Sulfuric Acid Mist. The permittee shall maintain and submit to the Department and AWQD, on a semiannual basis for a period of two years from the date each emissions unit begins co-firing petroleum coke, information demonstrating that the operational changes did not result in a significant emissions increase of sulfuric acid mist. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.
[Rule 62-210.200(12)(d), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010(A) & (B)]

Miscellaneous

D.71. Stack Height. The height of each boiler's exhaust stack for SJRPP Boiler No. 1 and No. 2 shall not be less than 640 feet above grade.
[PSD-FL-010 and PA 81-13]

D.72. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.
[Rule 62-204.800(7)(d), F.A.C.]

D.73. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:
(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used (see specific condition **D.42.**):

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

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

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

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209\ (F_{da} / F_{ca})$, then the following procedure shall be followed:

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

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

[40 CFR 60.46(d)(1)]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	**Brief Description**
-023	SJRPP: Coal Storage Yard and Transfer Systems

The coal receiving, storage and transfer systems at the coal storage yard support the operation of the two power boilers. The emissions units/points are as depicted in Table 6 (Revised; and, PSD-FL-010) and the appropriate part of Attachment SJRPP: Material Handling Transfer Points. Particulate matter emissions are controlled using fabric filter systems, water sprays, wetting agents, and full enclosures or partial enclosures, where appropriate.

{Permitting notes: The emissions unit is regulated under NSPS - 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Prevention of Significant Deterioration (PSD): PSD-FL-010 dated March 12, 1982; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated May 7, 1981; and, PPSA : PA 81-13 (revised 08/01/95).}

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

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

E.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions units 1 thru 16 and 4 thru 17, respectively.

E.2. <u>Hours of Operation</u>. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010]

E.3. <u>Controls</u>. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions units 4 thru 17 in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

<u>**Emission Limitations and Standards**</u>

{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.}

E.4. <u>Visible Emissions</u>. An owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, visible emissions greater than 10 percent opacity, as established in Revised Table 6, PSD-FL-010.
[PSD-FL-010, PA 81-13 and BACT]

E.5. Particulate Matter. Particulate matter emissions shall not exceed the limits established in Revised Table 6, PSD-FL-010.
[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.}

E.6. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

E.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

E.8. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.; Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting note: 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.}

E.9. Visible Emissions. EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity compliance pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests. See specific condition **E.10**.
[40 CFR 60.252(c); and, PSD-FL-010 and PA 81-13]

E.10. Particulate Matter. In accordance with Chapter 62-297, F.A.C., EPA Method 5 shall be used to determine compliance with the particulate matter emission limitations established in Revised Table 6, PSD-FL-010, for emissions units 4 thru 17 that exhaust through a stack. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests. See specific condition **E.9**.
[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

E.11. Operating Rate During Testing. Testing of emissions shall be conducted with the 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.

{Permitting note: The Revised Table 2 includes a summary of the various emissions points/ activities and their control systems for the Coal Storage Yard and Transfer Systems. The throughput rate amounts displayed represent approximately 74 percent of their maximum potential. Therefore, when any visible emissions test is being conducted, the emissions point/ activity being evaluated should be operating at or near its maximum potential throughput rate.}

[Rules 62-297.310(2) & (2)(b), 62-213.440(1) and 62-4.070(3), F.A.C.; Part XI, Rule 2.1101, JEPB]

E.12. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
[Rule 62-297.310(4)(a)2.c., F.A.C.; Part XI, Rule 2.1101, JEPB]

E.13. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

    a. Did not operate;

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

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

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

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

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

[Rule 62-297.310(7), F.A.C.; Part XI, Rule 2.1101, JEPB; and, SIP approved]

Recordkeeping and Reporting Requirements

E.14. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.

[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

E.15. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.; Part XI, Rule 2.1101, JEPB]

Miscellaneous Requirements.

E.16. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.
[Rule 62-204.800(7)(d), F.A.C.]

Section III. Emissions Units.

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-022	SJRPP: Limestone and Flyash Handling

Fugitive particulate matter emissions will be generated from limestone and flyash handling and storage systems. The emissions units/points are as depicted in Table 6 (Revised: PSD-FL-010) and the appropriate part of Attachment SJRPP: Material Handling Transfer Points. Various control strategies that will be used to minimize emissions are enclosures, wet suppression sprays, and control systems like baghouses. Visible emissions limits will be used to indicate compliance, with mass tests as backup requirements where visible emissions limits are violated.

{Permitting note(s): The emissions units are regulated under Rule 62-212.400(5), PSD NSR Review, which includes BACT (dated 05/07/81; PSD-FL-010 was issued March 12, 1982).}

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

Essential Potential to Emit (PTE) Parameters

F.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions units 17 thru 18 and 18 thru 19, respectively.

F.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB]

F.3. Controls. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions units 17 and 18 in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010]

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.}

F.4. Visible Emissions. Visible emissions shall not exceed the following:

a. Limestone and flyash handling systems	10% opacity
b. Limestone transfer points	10% opacity
c. Limestone silo	10% opacity
d. Limestone unloading (rail dumper)	10% opacity
e. Flyash silos	10% opacity

[PSD-FL-010 and PA 81-13]

F.5. Particulate Matter. Particulate matter emissions shall not exceed the following:

a. Limestone silo	0.05 lb/hr
b. Limestone hopper/transfer conveyors	0.65 lb/hr
c. Limestone transfer points	0.4 lb/hr
d. Limestone unloading (rail dumper)	0.1 lb/hr
e. Flyash handling system	0.2 lb/hr

[Rule 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010 and PA 81-13]

Excess Emissions

F.6. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.; and, Part III, Rule 2.301, JEPB]

F.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.; and, Part III, Rule 2.301, JEPB]

Monitoring of Operations

F.8. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

Test Methods and Procedures

{Permitting note: 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. EPA Method 9 shall be used to determine opacity compliance pursuant to Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A.
[Rule 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010 and PA 81-13]

F.10. Particulate Matter. In accordance with Chapter 62-297, F.A.C., EPA Method 5 shall be used to determine compliance with the particulate matter emission limitations established in Revised Table 6, PSD-FL-010, for emissions units 18 and 19 that exhaust through a stack. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests.
[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

F.11. Operating Rate During Testing. Testing of emissions shall be conducted with the 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.

{Permitting note: The Revised Table 2 includes a summary of the various emissions points/ activities and their control systems for the Limestone and Flyash Handling. The throughput rate amounts displayed represent approximately 74 percent of their maximum potential. Therefore, when any visible emissions test is being conducted, the emissions point/ activity being evaluated should be operating at or near its maximum potential throughput rate.}

[Rules 62-297.310(2) & (2)(b), 62-213.440(1) and 62-4.070(3), F.A.C.; and, Part XI, Rule 2.1101, JEPB]

F.12. Applicable Test Procedures.

(a) Required Sampling Time.

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

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

[Rule 62-297.310(4)(a)2.c., F.A.C.; and, Part XI, Rule 2.1101, JEPB]

F.13. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

    a. Did not operate;

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

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

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

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, Part XI, Rule 2.1101, JEPB and, SIP approved]

Recordkeeping and Reporting Requirements

F.14. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the AWQD 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 AWQD.
[Rule 62-210.700(6), F.A.C.; and, Part III, Rule 2.301, JEPB]

F.15. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the AWQD on the results of each such test.
(b) The required test report shall be filed with the AWQD as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Units.

Subsection G. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-024	SJRPP: Cooling Towers (2)

Fugitive particulate matter emissions from the cooling towers will be controlled with drift eliminators. No mass testing requirement will be imposed due to the physical layout.

{Permitting note(s): The emissions unit was regulated under Rule 62-212.400(5), PSD NSR Review (see PSD-FL-010 issued March 12, 1982).}

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

Essential Potential to Emit (PTE) Parameters

G.1. Revised Tables 2 and 6, PSD-FL-010, are incorporated by reference (attached) for emissions unit 19 and 20, respectively.

G.2. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; Part III, Rule 2.301, JEPB; and, PSD-FL-010 and PA 81-13]

G.3. Controls. The permittee shall maintain and continue to use the control systems and control techniques established to minimize particulate matter emissions from emissions unit 19 in Revised Table 2, PSD-FL-010.
[Rules 62-4.070 and 62-212.400(6), F.A.C.; Part IV, Rule 2.401, JEPB; and, PSD-FL-010 and PA 81-13]

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.}

G.4. Particulate Matter. Particulate matter emissions from each cooling tower shall not exceed 67 lbs/hr. No mass testing requirement will be imposed due to the physical layout.
[PSD-FL-010 and PA 81-13]

Section IV. This section is the Acid Rain Part.

Operated by: Jacksonville Electric Authority
ORIS codes: 0667: Northside Generating Station
0207: St. Johns River Power Park

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

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

E.U. ID No.	Description
-001	NGS Boiler No. 1
-002	NGS Boiler No. 2 (was placed on long-term reserve shutdown on 03/01/84)
-003	NGS Boiler No. 3
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.
[Chapter 62-213 and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-001[1]	1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	6182[3]	6182[3]	6182[3]	6182[3]
-002[1]	2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	6251[3]	6251[3]	6251[3]	6251[3]
-003[1]	3	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11061[3]	11061[3]	11061[3]	11061[3]

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-016[2]	1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11486[3]	11486[3]	11486[3]	11486[3]
-017[2]	2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	11279[3]	11279[3]	11279[3]	11279[3]

1 Northside Generating Station
2 St. Johns River Power Park
3 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.

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

A.4. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

A.5. Comments, notes, and justifications: Mr. Jon P. Eckenbach, Executive Vice President, Jacksonville Electric Authority, is the Designated Representative for Title IV purposes.

A.6. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

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

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

The emissions unit listed below is regulated under Acid Rain Part, Phase I/II, for:
Jacksonville Electric Authority
St. Johns River Power Park
Facility ID No.: 0310045
ORIS Code: 0207

E.U. ID No.	Brief Description
-016	SJRPP Boiler No. 1
-017	SJRPP Boiler No. 2

B.1. The owners and operators of these Phase I/II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:
a. Phase I permit issued 3/27/97.
[Chapter 62-213, F.A.C.]

B.2. Nitrogen oxide (NO_X) requirements for each Acid Rain unit are as follows:

E.U. ID No.	**EPA ID**	**NOx limit**[1]
-016	1	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit U1. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
-017	2	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit U2. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

1 Based on the Phase I/II NO_x Compliance Plan dated December 19, 1997.

B.3. Comments, notes, and justifications: none

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

Jacksonville Electric Authority **DRAFT Permit No.:** 0310045-008-AV
Northside Generating Station/St. Johns River Power Park **Facility ID No.:** 0310045

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.

Brief Description of Emissions Units and/or Activities:

I. Northside Generating Station.

-aaa Storage Tanks.

1. JEA Tank	Bunker C Storage	4,578,000 gallons
2. JEA Tank #12	Diesel Storage	4,200,000 gallons
3. JEA Tank #13	Diesel Storage	4,200,000 gallons
4. JEA Tank #14	Diesel Storage	4,200,000 gallons
5. JEA Tank	Waste Oil Storage - Unit 1	750 gallons
6. JEA Tank	Waste Oil Storage - Unit 2	1,000 gallons
7. JEA Tank	Waste Oil Storage - Unit 3	575 gallons
8. JEA Tank	Bunker C Storage	4,578,000 gallons
9. JEA Tank	Bunker C Storage	4,578,000 gallons
10. JEA Tank	Bunker C Storage	11,256,000 gallons
11. JEA Tank	Bunker C Storage	11,256,000 gallons
12. JEA Tank	Bunker C Storage	11,256,000 gallons
13. JEA Tank #10	Diesel Storage	168,000 gallons
14. JEA Tank #11	Diesel Storage	4,200,000 gallons

II. St. Johns River Power Park.

-bbb Storage Tanks.

1. JEA Tank: Emergency Diesel Fire Pump	Diesel Fuel Storage	1,123 gallons
2. JEA Tank: AQCS Emergency Diesel Generator Day Tank	Diesel Fuel Storage	561 gallons
3. JEA Tank	Diesel Fuel Storage	636,106 gallons
4. JEA Tank: Coal/Limestone Fuel Storage	Diesel Fuel Storage	10,069 gallons
5. JEA Tank: Ash Landfill Fuel Storage	Diesel Fuel Storage	10,069 gallons
6. JEA Tank: Power Block Emergency Generator Fuel Storage	Diesel Fuel Storage	4,015 gallons
7. JEA Tank	Gasoline Storage	10,069 gallons

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

Jacksonville Electric Authority **DRAFT Permit No.:** 0310045-008-AV
Northside Generating Station/St. Johns River Power Park **Facility ID. No.:** 0310045

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities:

I. Northside Generating Station.

A. Storage Tanks.

1. JEA Tank	Magnesium Oxide	9,600 gallons
2. JEA Tank	Petrolite	6,500 gallons
3. JEA Tank	Lube Oil - Unit 1	10,000 gallons
4. JEA Tank	Lube Oil - Unit 2	10,000 gallons
5. JEA Tank	Mineral Acid	11,500 gallons
6. JEA Tank	Mineral Acid	11,500 gallons
7. JEA Tank	Caustic - East	10,000 gallons
8. JEA Tank	Caustic - West	10,000 gallons
9. JEA Tank	Hypochlorite	12,000 gallons
10. JEA Tank	Hypochlorite	12,000 gallons
11. JEA Tank	Lube Oil	18,000 gallons
12. JEA Tank	Lube Oil	7,000 gallons

II. St. Johns River Power Park.

A. AQCS Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

B. Power Block Emergency Generator.

1. The emergency generator has historically fired less than 10,000 gallons per year of diesel fuel. The emergency generator draws its fuel from a single diesel fuel oil storage tank (the fuel oil has a maximum fuel sulfur content limit of 0.76%, by weight).

C. Storage Tanks.

1. JEA Tank	Lube Oil	10,000 gallons
2. JEA Tank	Lube Oil	18,000 gallons
3. JEA Tank	Sulfuric Acid	6,000 gallons
4. JEA Tank	Sulfuric Acid	10,000 gallons
5. JEA Tank	Sulfuric Acid	6,000 gallons
6. JEA Tank	Sulfuric Acid	6,000 gallons
7. JEA Tank	Caustic	10,000 gallons
8. JEA Tank	Caustic	6,000 gallons
9. JEA Tank	Hydrazine	6,000 gallons
10. JEA Tank	Hypochlorite	6,000 gallons

III. NGS Boilers Nos. 1, 2 and 3, and SJRPP Boilers Nos. 1 and 2.

1. Evaporation of on-site generated boiler non-hazardous cleaning chemicals (cirtosolv and ammonia). This activity occurs once every three to five years or longer.

Appendix H-1: Permit History

Jacksonville Electric Authority
Northside Generating Station/St. Johns River Power Park

DRAFT Permit No.: 0310045-008-AV
Facility ID No.: 0310045

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type [1]
All	Facility	0310045-001-AV	01/01/1999	12/31/2003	Initial
-016	SJRPP Steam Boiler #1 [1]	0310045-002-AV	01/10/1999	12/31/2003	Revision
-017	SJRPP Steam Boiler #2	0310045-002-AV	01/10/1999	12/31/2003	Revision
-006	NGS CT #3 [2]	0310045-004-AC	04/20/2000	10/30/2001	Construction (mod.)
		0310045-005-AC	07/17/2000	07/17/2005	Construction (mod.)
		0310045-006-AC	04/04/2001	04/04/2006	Construction (mod.)
		0310045-008-AV	Pending [3]	12/31/2003	Revision
-007	NGS CT #4	0310045-004-AC	04/20/2000	10/30/2001	Construction (mod.)
		0310045-005-AC	07/17/2000	07/17/2005	Construction (mod.)
		0310045-006-AC	04/04/2001	04/04/2006	Construction (mod.)
		0310045-008-AV	Pending [3]	12/31/2003	Revision
-008	NGS CT #5	0310045-004-AC	04/20/2000	10/30/2001	Construction (mod.)
		0310045-005-AC	07/17/2000	07/17/2005	Construction (mod.)
		0310045-006-AC	04/04/2001	04/04/2006	Construction (mod.)
		0310045-008-AV	Pending [3]	12/31/2003	Revision
-009	NGS CT #6	0310045-004-AC	04/20/2000	10/30/2001	Construction (mod.)
		0310045-005-AC	07/17/2000	07/17/2005	Construction (mod.)
		0310045-006-AC	04/04/2001	04/04/2006	Construction (mod.)
		0310045-008-AV	Pending [3]	12/31/2003	Revision

[1] St. Johns River Power Park (SJRPP).
[2] Northside Generating Station (NGS) Combustion Turbine (CT).
[3] Change to an actual date, which is day 55 from the date of posting the PROPOSED Permit for EPA review (see confirmation e-mail from Tallahassee) or the date that EPA confirms resolvement of any objections.

Jacksonville Electric Authority

Operation and Maintenance Plan

Operation and Maintenance

Following is a list of activities to be accomplished for the control of particulate emissions from units in or impacting the Duval County maintenance areas. These schedules apply to each on-line unit.

Daily:

1. Check and clean burners (renew tips as necessary) daily.
2. Conduct one complete soot-blowing cycle (or as needed).
3. Maintain optimum fuel oil temperature and pressure at all times.

Weekly:

1. Clean low pressure fuel oil strainers (more frequently if required).
2. Clean other fuel oil strainers as needed by monitoring the pressure drop.

Annually:

1. Clean the boiler and inspect baffles.
2. Inspect the:
   - (a) wind box;
   - (b) registers;
   - (c) diffusers;
   - (d) refractory throat;
   - (e) scanners;
   - (f) ignitors.
3. Adjust the air registers for optimum flame pattern with assistance from Engineering Services.
4. Replace burner tips (more frequently if required).

As Needed:

1. Wash furnace and air heaters.

Major Outages:

1.	Overhaul the:	(a)	turbine/generator
		(b)	boiler and auxiliary equipment.
2.	Calibrate the:	(a)	flow meters including sensing line checks;
		(b)	pneumatic controls;
		c)	temperature gauges.

Performance Parameters

The following operational parameters are to be recorded on a bi-hourly basis.

1. Steam flow.
2. Burner oil pressure.
3. Burner oil temperature.

Fuel Type: Number 6 residual oil unless otherwise stated.

Records

Records of all operating data and maintenance procedures listed herein shall be retained at the Generating Station for review, upon request, for a period of five (5) years.

LB/O&MPlan.doc
04/29/98

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 9, 1997

Certified Mail - Return Receipt Requested

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

Dear Mr. Piper:

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

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

Sincerely,

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

MDH:ym

cc: Dotty Diltz, FDEP
Pat Comer, FDEP

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

ORDER CORRECTING SCRIVENER'S ERROR

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

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

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

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

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

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

ORDER ON REQUEST FOR ALTERNATE PROCEDURES AND REQUIREMENTS

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

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

FINDINGS OF FACT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

CONCLUSIONS OF LAW

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

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

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

ORDER

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

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

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

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

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

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

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

PETITION FOR ADMINISTRATIVE REVIEW

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

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

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

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

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

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

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

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

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

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

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

A request for mediation must contain the following information:

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

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

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

The agreement to mediate must include the following:

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

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

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

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

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

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

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

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

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

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

The petition must specify the following information:

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

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

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

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

(e) The type of action requested;

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

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

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

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

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

RIGHT TO APPEAL

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

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

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

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.

Clerk 3-18-97
Date

FLORIDA ELECTRIC POWER COORDINATING GROUP, INC. (FCG)
405 REO STREET, SUITE 100 • (813) 289-5644 • FAX (813) 289-5646
TAMPA, FLORIDA 33609-1004

January 28, 1997

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

RECEIVED
JAN 28 1997
BUREAU OF
AIR REGULATION

RE: Comments Regarding Draft Title V Permits

Dear Mr. Fancy:

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

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

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

Exhibit 1

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

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

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

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

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

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

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

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

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

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

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

Sincerely,

Rich Piper

Rich Piper, Chair
FCG Air Subcommittee

Enclosures

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

85601

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 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 85 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 Controls[3-5]

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

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

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

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

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

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

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

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

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

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

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

[b] SCC = Source Classification Code.

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

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

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

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

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

[b] SCC = Source Classification Code.

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

Table 1.4-2 (cont.).

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

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

[f] Emission factors apply to packaged boilers only.

Table 1.4-3 (Metric And English Units). EMISSION FACTORS FOR CARBON DIOXIDE (CO_2) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

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

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

[b] SCC = Source Classification Code.

[c] References 10,22-23.

[d] References 9-10,18.

[e] ND = no data.

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

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

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

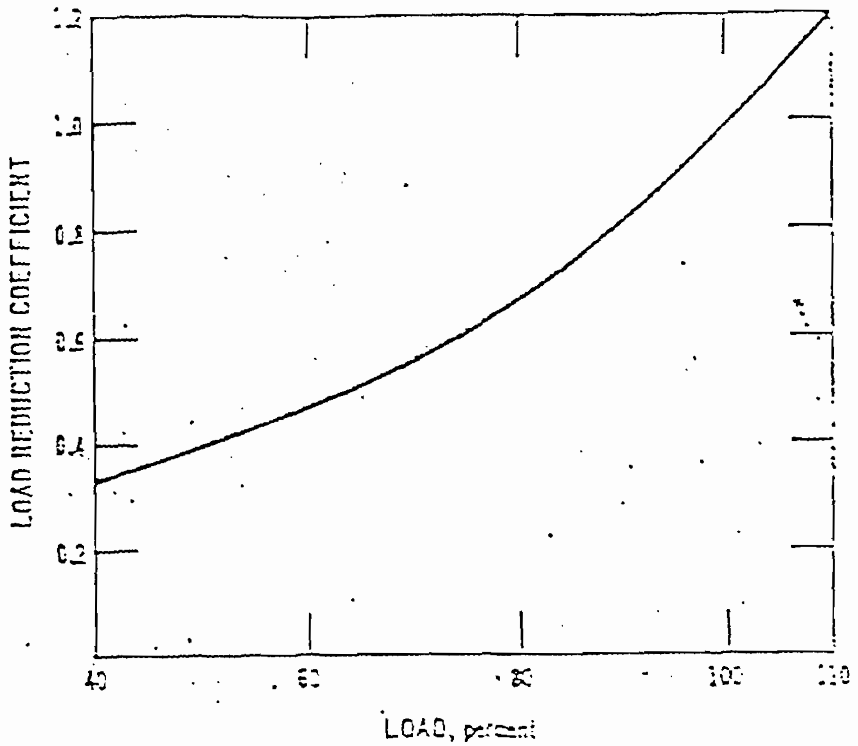

Figure 1.4-1. Load reduction coefficient as a function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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40 CFR 60 Subpart A-General Provisions
(Version dated 07/23/97)

These conditions are based on the July 1996 CFR version.

[Applicability note: These conditions are for an NSPS emissions unit (a.k.a. "federal facility") that has been built and has conducted the initial performance test(s) in accordance with 40 CFR 60.8.]

{Note: Rule 62-204.800(d), F.A.C., did not adopt/incorporate 40 CFR 60.4, 40 CFR 60.16, and 40 CFR 60.17.}

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1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

40 CFR 60.7 Notification and record keeping.

2. The owner or operator subject to the provisions of 40 CFR 60 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.
[40 CFR 60.7(a)(4)]

3. The owner or operator subject to the provisions of 40 CFR 60 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.
[40 CFR 60.7(b)]

4. Each 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.
[40 CFR 60.7(c)(1), (2), (3), and (4)]

5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) 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} (electronic file name: figure1.doc)

[40 CFR 60.7(d)(1) and (2)]

6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

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

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After

demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1)]

7. Any owner or operator subject to the provisions of 40 CFR 60 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 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

40 CFR 60.8 Performance tests.

8. 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.
[40 CFR 60.8(c)]

40 CFR 60.11 Compliance with standards and maintenance requirements.

9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
[40 CFR 60.11(a)]

10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
[40 CFR 60.11(c)]

12. 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.
[40 CFR 60.11(d)]

13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she 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 EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11(e)(5)]

40 CFR 60.12 Circumvention.

14. No owner or operator subject to the provisions of 40 CFR 60 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]

40 CFR 60.13 Monitoring requirements.

15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 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 of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
[40 CFR 60.13(a)]

16. 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 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 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 60.8 is conducted.
[40 CFR 60.13(c)(1)]

17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) 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.
[40 CFR 60.13(d)(1) and (2)]

18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) 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.
[40 CFR 60.13(e)(1) and (2)]

19. All continuous monitoring systems (CMS) 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.
[40 CFR 60.13(f)]

20. 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 (CMS) 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.
[40 CFR 60.13(g)]

21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally

spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

[electronic file name: 40CFR60a.doc]

Attachment NGS: CT Heat Input Nominal Values

NORTHSIDE STATION COMBUSTION TURBINES
BASE LOAD MW vs TEMPERATURE

#	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR
1	20	67.97	67.63	868	60	58.77	58.43	747
2	21	67.74	67.40	865	61	58.54	58.20	744
3	22	67.51	67.17	861	62	58.31	57.97	741
4	23	67.28	66.94	858	63	58.08	57.74	738
5	24	67.05	66.71	855	64	57.85	57.51	735
6	25	66.82	66.48	852	65	57.62	57.28	733
7	26	66.59	66.25	849	66	57.39	57.05	730
8	27	66.36	66.02	846	67	57.16	56.82	727
9	28	66.13	65.79	842	68	56.93	56.59	724
10	29	65.90	65.56	839	69	56.70	56.36	721
11	30	65.67	65.33	836	70	56.47	56.13	719
12	31	65.44	65.10	833	71	56.24	55.90	716
13	32	65.21	64.87	830	72	56.01	55.67	713
14	33	64.98	64.64	827	73	55.78	55.44	710
15	34	64.75	64.41	824	74	55.55	55.21	708
16	35	64.52	64.18	821	75	55.32	54.98	705
17	36	64.29	63.95	818	76	55.09	54.75	702
18	37	64.06	63.72	815	77	54.86	54.52	699
19	38	63.83	63.49	812	78	54.63	54.29	697
20	39	63.60	63.26	809	79	54.40	54.06	694
21	40	63.37	63.03	806	80	54.17	53.83	691
22	41	63.14	62.80	802	81	53.94	53.60	689
23	42	62.91	62.57	799	82	53.71	53.37	686
24	43	62.68	62.34	796	83	53.48	53.14	683
25	44	62.45	62.11	793	84	53.25	52.91	681
26	45	62.22	61.88	791	85	53.02	52.68	678
27	46	61.99	61.65	788	86	52.79	52.45	675
28	47	61.76	61.42	785	87	52.56	52.22	673
29	48	61.53	61.19	782	88	52.33	51.99	670
30	49	61.30	60.96	779	89	52.10	51.76	667
31	50	61.07	60.73	776	90	51.87	51.53	665
32	51	60.84	60.50	773	91	51.64	51.30	662
33	52	60.61	60.27	770	92	51.41	51.07	660
34	53	60.38	60.04	767	93	51.18	50.84	657
35	54	60.15	59.81	764	94	50.95	50.61	654
36	55	59.92	59.58	761	95	50.72	50.38	652
37	56	59.69	59.35	758	96	50.49	50.15	649
38	57	59.46	59.12	755	97	50.26	49.92	647
39	58	59.23	58.89	753	98	50.03	49.69	644
40	59	59.00	58.66	750	99	49.80	49.46	641
41	60	58.77	58.43	747	100	49.57	49.23	639

KSCT

Y INTERCEPT	72.576
SLOPE	0.2301

DISPATCH HEAT RATE CURVES

A =	1.78910E+02
B =	8.82453E+00
C =	-1.50705E-02
D =	5.20028E-04
AA =	3.40192E-01
BB =	9.99987E-01
CC =	1.79499E-07
DATE:	05/21/93

Attachment SJRPP: Material Handling Transfer Points

SJRPP Material Handling Transfer Points for Permitting

	Limestone	Points
1)	Limestone receiving bin with 3 Unloading hoppers	1
2)	Unloading hoppers to FLD-1 Belt	3
3)	FLD-1 to L0	1
4)	L0 to L1	1
5)	L1 to L2	1
6)	L2 to Storage Pile	1
7)	Reclaim hopper	1
8)	Hopper to 9LC-02	1
9)	9LC-02 to Silos(2)	2
10)	Silos to 1LC-01,2LC-01 (to ball mills)	2
	Total	14

	Coal-Yard	
1)	Receiving bin with 4 Unloading hoppers	1
2)	4 Unloading hoppers to FCD-1,2,3,4	4
3)	FCD-1,2,3,4 to C0	4
4)	C0 to C1	1
5)	C1 to C2	1
	C1 to emergency stackout	1
6)	C2 to C4	1
7)	C4 to C5	1
	C4 to CT6	1
8)	C5 to C6	1
9)	C6 to storage pile	1
	Reclaim to C6 (grab and dump)	2
	C6 to C4	1
10)	Surge Bins	
	C2 to Surge Bin	1
	C3 to Surge Bin	1
	C4 to Surge Bin	1
	Surge Bin to FCR-A,B	2
11)	FCR-A,B to Crushers (2)	2
	Crushers (2)	2
	Crushers to C7,8	2
12)	C7,8 to C9,10	2
13)	C9,10 to 14 Coal Storage Silos	14
	Total	47

	Coal-Shipunloader	Points
14)	Bucket to Hopper (grab & dump)	2
15)	Hopper to Belt	1
16)	Hopper Belt to CT1	1
17)	CT1 to CT2	1
18)	CT2 to CT3	1
19)	CT3 to CT4	1
20)	Reclaimer to CT4 (grab, dump,dump)	3
21)	CT4 to CT5	1
	CT4 to S1 traveling conveyor	1
	S1 Traveling conv. to S2 boom conv.	1
	S2 boom conv to storage pile	1
22)	CT5 to C2	1
23)	CT6 to CT4	1
	Total	16

	Coal-Petcoke Feeder System	
24)	Hopper	1
	Hopper to SPC-1	1
	SPC-1 to FC-1	1
	FC-1 to C4	1
	Total	4

	Fly & Bottom Ash Handling System	
25)	Flyash	
	U#1-A&B Saleable silo Baghouse (2) & roof vents (2)	4
	U#1-1 Non-saleable Silo Baghouse & roof vent	2
	U#1-A loadout Silo discharge (2) & roof vent (1)	3
	U#1-B loadout Silo discharge (2) & roof vent (1)	3
	U#2-A&B Saleable silo Baghouse (2) & roof vents (2)	4
	U#2-A Non-saleable Silo Baghouse & roof vent	2
	U#2-A loadout Silo discharge (2) & roof vent (1)	3
	U#2-B loadout Silo discharge (2) & roof vent (1)	3
26)	Bottom Ash	
	U#1-A&B Silo to conveyor belt	2
	Conveyor belt to truck	1
	U#2-A&B Silo to conveyor belt	2
	Conveyor belt to truck	1
	Total	30

Grand Total 111

Table 6. Allowable Emission Limits (Revised: From PSD Permit)

	Emission Unit	SO_2	NO_x (lb/hour: lb/MMBtu)	PM (Revised Original)	Opacity (Percent)
1.	Steam Generating Boiler No.1 (6,144 MMBtu/hr maximum heat input)	4,669.: 0.76 (30-day rolling average)	3.686: 0.6	184 0.03	20
2.	Steam Generatinq Boller No. 2 (6,144 MMBtu/hr maximum heat input)	4,669: 0.76 (30-day rolling average)	3,686: 0.6	184: 0.03	20
3.	Auxiliary ooilers (254 MMBtu/hr maximum heat input total)	203: 0.8		25.0: 0.1	20
4.	Ship Unloading (2 Grab Buckets)			1.0	10
5.	Feeders to Conveyor A (2 Wet Suppre~sion points)*			0.13	10
6.	Conveyor Transfers 1 & 2 (2 points)*			0.57	10
7.	Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8.	Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9.	Traveling Stacker (3 points)*			0.8	10
10.	Bucket Wheel Reclaimer (2 points)*			0.6	10
11.	Ship unloading facility coal storage pile			1.6	10
12.	Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13.	Rail car unloading (Rotary Dumper)			5	10
14.	Coal handling transfer points (6 wet suppression points)			5(each)	10
15.	Coal handling transfer points (11 dry colleccion)			0.1(each)	10
16.	Coal storage at plant. (10 acres active)			0.5	10
17.	Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18.	Limestone unloading (rail dumper)			0.1	10
19.	Limestone transfer points			0.4(each)	10
20.	Cooling towers			67(Each tower)	N/A

* Revised emission unit, May 1986.