Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

September 12, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James O. Vick, Director
Environmental Affairs
Gulf Power Company
One Energy Place
Pensacola, Florida 32520

Re: Oleander Power Project Unit 5
Simple Cycle Combustion Turbine
DEP File No. 0090180-003-AC (PSD-FL-377)

Dear Mr. Vick:

Enclosed is the Department's preliminary determination to issue an Air Construction Permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Oleander Power Project, L.P. to construct a 190 megawatt simple cycle combustion turbine unit, stack, and fuel oil storage tank at the Oleander Power Project in Brevard County. The documents include: the "Intent to Issue Air Construction Permit"; the "Public Notice of Intent to Issue Air Construction Permit"; the Department's "Technical Evaluation and Preliminary Determination"; and the Draft Permit.

The PUBLIC NOTICE must be published one time only in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation 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 Department's proposed action to A. A. Linero at the above letterhead address. If you have any questions, please call Cindy Mulkey at 850/921-8968 (review engineer) or Debbie Nelson at 850/921-9537.

Sincerely,

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/aal/cm

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:

Mayor, City of Cocoa Beach
Post Office Box 322430
Cocoa Beach, Florida 32932-2430

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X B Nichols ☐ Agent ☐ Addressee

B. Received by (Printed Name) B Nichols | C. Date of Delivery 9/14/06

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

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
(Transfer from service label) 7000 1670 0013 3110 1229

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 1229

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mayor, City of Cocoa Beach
Post Office Box 322430
Cocoa Beach, Florida 32932-2430

PS Form 3800, May 2000 See Reverse for Instructions

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 1212

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. James O. Vick, Director
Environmental Affairs
Gulf Power Company
One Energy Place
Pensacola, Florida 32520

PS Form 3800, May 2000 See Reverse for Instructions

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. James O. Vick, Director
Environmental Affairs
Gulf Power Company
One Energy Place
Pensacola, Florida 32520

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X James Blakely ☒ Agent ☐ Addressee

B. Received by (Printed Name) James Blakely | C. Date of Delivery 9-13

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

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
(Transfer from service label) 7000 1670 0013 3110 1212

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

In the Matter of an
Application for Permit by:

Oleander Power Project, L.P.
555 Townsend Road
Cocoa, Florida 32926

Authorized Representative:
Mr. James O. Vick

DEP File No. 0090180-003-AC
Draft Permit No. PSD-FL-377
Oleander Power Project
Unit 5 Simple Cycle Combustion Turbine
Brevard County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an Air Construction Permit, copy of Draft Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Oleander Power Project, L.P., applied on May 4, 2006 to the Department for an Air Construction Permit to construct a 190 megawatt simple cycle combustion turbine, Unit 5, at the existing Oleander Power Project in the city of Cocoa, Brevard County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an Air Construction Permit pursuant to the Rules for the Prevention of Significant Deterioration of Air Quality (PSD) is required.

The Department intends to issue this Air Construction Permit based on the belief that reasonable assurances have been provided to indicate that operation of these emissions units will not adversely impact air quality, and the emissions units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rules 62-110.106(7)(a)1., and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/921-9533). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under 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 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) of the Florida Statutes 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), however, any person who asked the Department 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 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, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department'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.

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 notice. 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.

Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L. Vielhauer
Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail or by electronic mail before the close of business on 9/12/06 to the persons listed:

James O. Vick, Gulf Power Company*
Allison Little, Gulf Power Company
Mayor, City of Cocoa*
Chair, Brevard County BCC
Gregg Worley, EPA Region 4
John Bunyak, National Park Service
Len Kozlov, DEP CD
Thomas W. Davis, P.E., ECT, Inc.

Clerk Stamp

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

(Clerk) 9/12/06 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0090180-003-AC, PSD-FL-377

Oleander Power Project Unit 5
Simple Cycle Combustion Turbine-Electrical Generator

Brevard County

The Department of Environmental Protection (Department) gives notice of its intent to issue an Air Construction Permit to Oleander Power Project, L.P. The permit is to construct a 190 megawatt (MW) simple cycle combustion turbine-electrical generator (CT) to be known as Unit 5 at the Oleander Power Project in the City of Cocoa, Brevard County. A review under the Rules for the Prevention of Significant Deterioration of Air Quality (PSD) and a Best Available Control Technology (BACT) determination were required for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}) pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.). The applicant's name and address are Oleander Power Project, L.P., 555 Townsend Road, Cocoa, Florida 32926.

The original Air Construction Permit issued in 1999 authorized construction of five General Electric 7FA simple cycle CTs with 60-foot stacks and two 1.8 million gallon fuel oil storage tanks. Only four CTs with stacks and the two fuel oil storage tanks were constructed. This draft permitting action re-authorizes construction of the fifth 190 MW CT, a 60-foot stack and a smaller fuel oil storage tank with a nominal capacity of 900,000 gallons.

Unit 5 will be an intermittent duty CT (typically known as a peaking unit) and will fire natural gas as the primary fuel and No. 2 low sulfur fuel oil as back-up fuel. Unit 5 will be permitted to operate a total of 3,390 hours per year with a maximum of 500 hours of fuel oil firing. The Department has determined that BACT for NO_X is 9.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2). The limit will be achieved by use of inherently clean natural gas and use of Dry Low NO_X/CO combustors.

A limit of 42 ppmvd NO_X @15% O_2 will apply while firing back-up fuel oil and will be achieved by water injection into the combustors for flame temperature control. Emissions of carbon monoxide (CO), PM/PM_{10}, sulfuric acid mist (SAM), sulfur dioxide (SO_2), volatile organic compounds (VOCs) and visible emissions (Opacity) will be minimized by the efficient, high-temperature combustion of clean fuels.

Estimates of maximum potential annual emissions from CT Unit 5 are summarized in the following table.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	77.0	100	No
NO_X	174.5	40	Yes
PM/PM_{10}	34.5/34.5	25/15	Yes
SO_2	37.1	40	No
SAM	2.7	7	No
VOC	11.4	40	No
Mercury	0.0006	0.1	No
Pb	0.0495	0.6	No
Formaldehyde	0.655	Not Applicable	No

According to the applicant and as verified by the Department, maximum predicted air quality impacts due to worst case emissions from the proposed new project are less than the significant impact levels applicable to all PSD Class II areas. Therefore, multi-source (PSD Increment) modeling was not required. The impacts to the nearest Class I area (Chassahowitzka National Wildlife Refuge on the Gulf coast) will be negligible. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

The Department will issue the 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 Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under 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 filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) 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) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department 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 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department'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 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, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department'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 Department's final action may be different from the position taken by it in this notice. 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 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/921-9533

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section at the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. Key documents related to this permitting action are available at: www.dep.state.fl.us/Air/permitting/construction/oleander.htm

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Oleander Power Project, L.P.

190 MW Simple Cycle Gas Turbine

Cocoa, Brevard County

DEP File No. 0090180-003-AC (PSD-FL-377)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation – Air Permitting South
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

September 12, 2006

I. APPLICATION INFORMATION

A. APPLICANT

Oleander Power Project, L.P.
555 Townsend Road
Cocoa, Florida 32926

Authorized Representative

James O. Vick, Director Environmental Affairs
Gulf Power Company
One Energy Place
Pensacola, Florida 32520

B. PROCESSING SCHEDULE

- Application for Air Construction Permit received on May 4, 2006;
- Department's Request for Additional Information dated June 2, 2006;
- Applicant's Response to Request for Additional Information Received July 13, 2006 (complete);
- Department's Intent to Issue and Public Notice Package dated September 12, 2006.

C. FACILITY LOCATION

Oleander Power Project (OPP) is located in Cocoa just off Interstate 95 and State Road 520 in Brevard County. The site is 175 km from the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area, the Chassahowitzka National Wildlife Refuge. The UTM coordinates for this site are Zone 17, 520.1 km East and 3,137.6 km North. The locations of Cocoa and OPP are shown in the following figures.

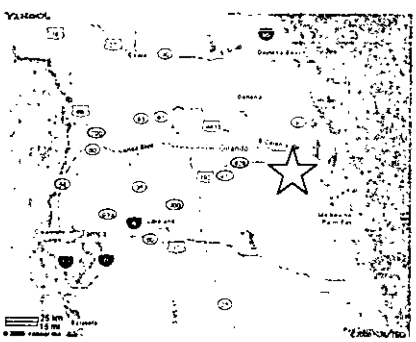


Figure 1. Location of Cocoa

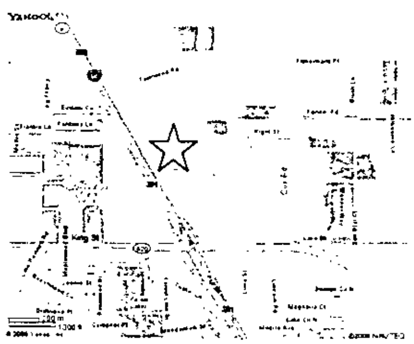


Figure 2. OPP Location

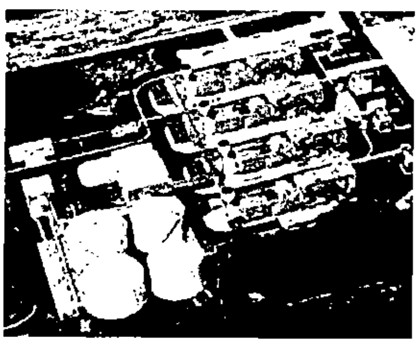


Figure 3. Site Aerial Photograph

D. FACILITY DESCRIPTION

The regulated emissions units at the existing Oleander Power Project include four 190 megawatt (MW) General Electric 7FA simple cycle combustion turbine-electric generators (CT Units 001 through 004). The CTs have evaporative coolers, Dry Low NO_X/CO (DLN) combustors and water injection equipment and can fire natural gas or No. 2 low sulfur (0.05 percent) fuel oil. The facility also includes four 60-foot stacks, two 1.8 million-gallon fuel oil storage tanks (Units 006 and 007) and water storage tanks. The original application included the construction of five combustion turbines (CTs), of which only four were constructed.

The facility's Standard Industrial Classification Codes are listed in the following Table:

Table 1. Oleander Power Project SIC Codes

STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)		
Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

E. REGULATORY CATEGORIES

Title I, Part C, Clean Air Act (CAA): The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility does not fall into one of the 28 Prevention of Significant Deterioration (PSD) Major Facility Categories with the lower PSD applicability threshold therefore the 250 tons per year threshold is applicable. Potential emissions of at least one regulated pollutant exceed 250 tons per year, therefore the facility is classified as a "Major Stationary Source" of air pollution with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration of Air Quality.

Title I, Section 111, CAA: Unit 5 will be subject to 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005).

Title I, Section 112, CAA: The facility is not a "Major Source" of hazardous air pollutants (HAPs). Unit 005 will not be subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines.

Title IV, CAA: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, CAA: The facility is a Title V or "Major Source of Air Pollution" in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

F. PROJECT DESCRIPTION AS PROPOSED BY APPLICANT

The applicant proposes to install one 190 megawatt (MW) General Electric (GE) 7FA simple cycle combustion turbine-electrical generator (CT Unit 5, ID 005) equipped with evaporative cooling, DLN combustors and water injection equipment. OPP also plans to install a new 60-foot stack and a nominal 900,000 gallon distillate fuel oil storage tank.

Additional project details, as proposed, are described below:

Fuel: Operation of Unit 5 for a total of 3,390 hours per year using natural gas as the primary fuel. The use of low sulfur fuel oil (0.05 % sulfur) as a back up fuel has been requested for up to 1000 hours, included in the 3,390.

Controls: NO_X emission will be reduced with DLN combustion technology while firing natural gas, and water injection while firing fuel oil. Advanced burner design with good combustion practices will be used to minimize incomplete combustion of CO, PM_{10}, and VOC. The use of natural gas and restricted operation on fuel oil will minimize emissions of SO_2 and sulfuric acid mist (SAM).

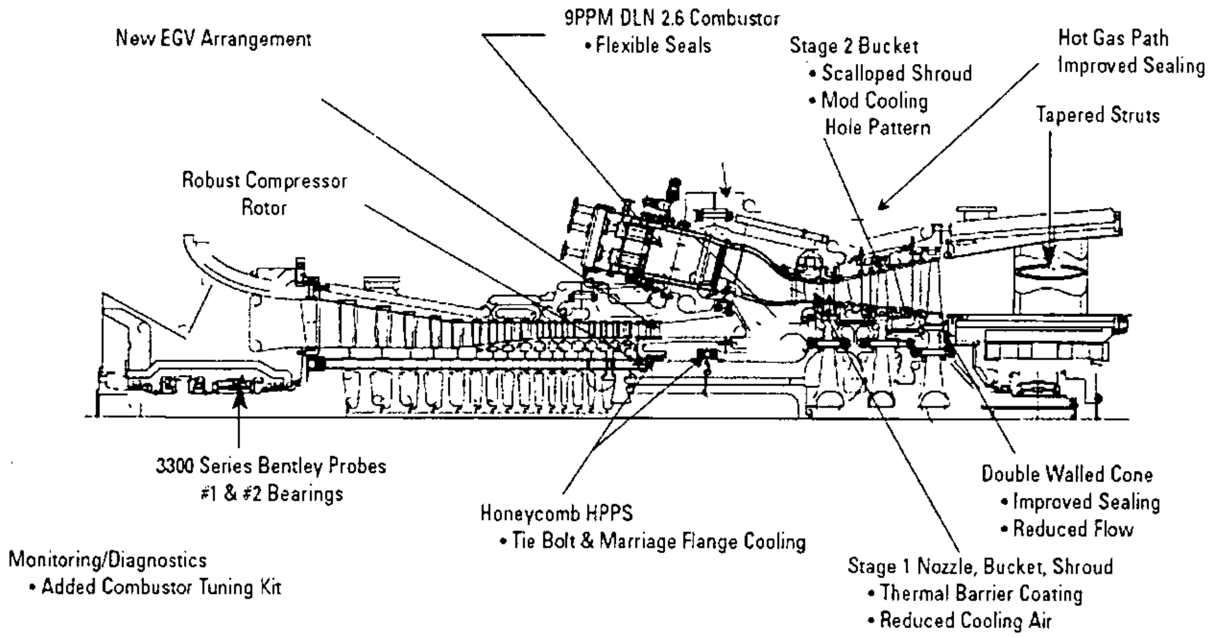
Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determination. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

Stack parameters: Unit 5 will have a stack that is 60 feet tall with an approximate exit diameter of 22 feet. The following table summarizes the exhaust characteristics of the unit. Values given are <u>approximate</u> for operation at 59 degrees Fahrenheit (°F) and the characteristics of the actual delivered unit may differ somewhat. At 59 °F, the nominal capacity is approximately 170 MW when firing natural gas whereas the capacity is greater (nominally 180 to 190 MW) at lower temperature or when firing fuel oil.

Table 2. Approximate Exhaust Characteristics of Unit 5 at 100% Load and 59° F

Fuel	Total Heat Input (LHV)	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Flow ACFM @ 15% O_2
Gas	1722 mmBtu/hr	59° F	1,111 °F	2,882,847
Oil	1920 mmBtu/hr	59° F	1,095 °F	3,297,214

The key components, with a focus on fairly recent improvements, of the GE 7FA CT are shown in the "quarter section" internal diagram. The overall look can be appreciated by the "three-quarter" section graphic of the similar 7FB following the diagram.



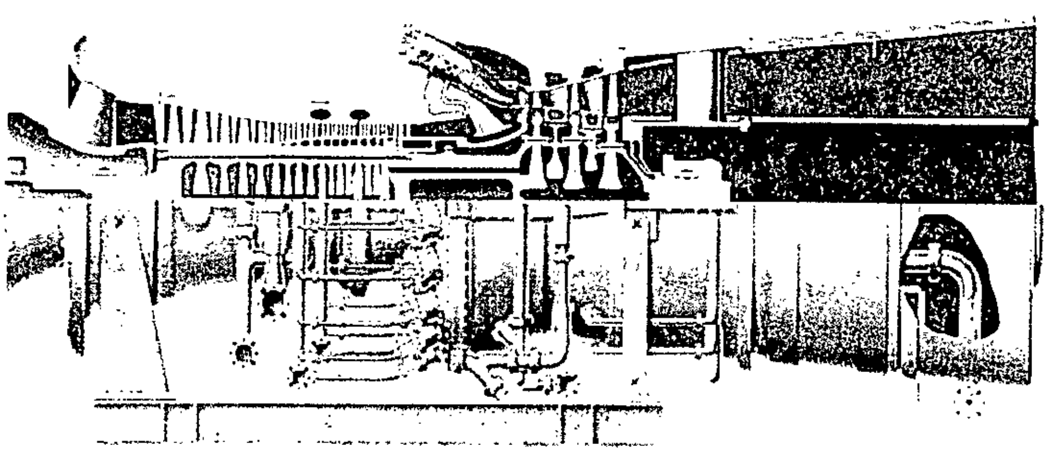


Figure 4. Quarter Section of GE 7FA (top). Three-Quarter Section of GE 7FB (bottom) (GE Reports)

G. Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 4) where it is compressed by a pressure ratio of about 15.5 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

In general, flame temperatures in a typical combustor section can reach 3600° F. Units such as the GE 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2500° F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1000 °F and high excess oxygen and is available for additional energy recovery.

There are three basic operating cycles for gas turbines. These are simple, regenerative, and combined cycles. In the OPP project, the unit will operate in simple cycle mode only, meaning that the gas turbine drives an electric generator while the exhausted gases are directed through the stack with no additional heat recovery.

II. RULE APPLICABILITY

A. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the F.A.C.

Chapter	Description
62-4	Permitting Requirements
62-204	Air Pollution Control (Includes Adoption of Federal Regulations)
62-210	Stationary Sources – General Requirements
62-212	Stationary Sources – Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Stationary Sources – Emission Limiting Standards
62-297	Stationary Sources – Emissions Monitoring

B. Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	Standards of Performance for New Stationary Sources (NSPS)
Part 72	Acid Rain – Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain – Continuous Emissions Monitoring
Part 76	Acid Rain – Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain – Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

C. PSD PRECONSTRUCTION REVIEW REQUIREMENTS

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as described in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant; or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories; or
- 5 tons per year of lead.

For new PSD-major facilities and modifications to existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) identified in Rule 62-210.200(243), F.A.C. Each pollutant exceeding the respective SER is considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions, and evaluate the air quality impacts. Although a facility may be considered a "major stationary source" with respect to PSD because of only one regulated pollutant, it is required to implement BACT for each "PSD-significant" pollutant. In accordance with Rule 62-212.400(4), F.A.C., for the construction of any new "major stationary source" or the major "modification" of any existing major stationary source, the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design an plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

"Best Available Control Technology" or "BACT" as defined in Rule 62-210.200(38), F.A.C. is as follows:

(a) *An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:*
   1. *Energy, environmental and economic impacts, and other costs,*
   2. *All scientific, engineering, and technical material and other information available to the Department; and*
   3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for eh application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

(c) *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

(d) *In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.[1]

In addition to a determination of BACT, PSD review also requires an Air Quality Analysis for each pollutant exceeding the SER. The Air Quality Analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

D. PSD APPLICABILITY FOR THE PROJECT

The project will result in emissions of carbon monoxide, nitrogen oxides, sulfur dioxides, particulate matter, sulfuric acid mist (SAM), volatile organic compounds, lead (Pb), mercury (Hg), formaldehyde, and flourides. The following table summarizes the annual potential emissions in tons per year (TPY) from the project as proposed by the applicant.

Table 3. Estimate of Potential Annual Emissions as Proposed by Applicant.

Pollutant	Project Emissions TPY	PSD Significant Emission Rate TPY	PSD Review Required?
NO_X	243.1	40	Yes
SO_2	58.9	40	Yes
CO	83.7	100	No
PM	38.5	25	Yes
PM_{10}	38.5	15	Yes
VOC	12.9	40	No
SAM	4.5	7	No
Mercury	0.0012	0.1	No
Lead	0.0489	0.6	No
Formaldehyde	0.672	Not Applicable	NAo
Total Fluorides	Negligible	3	No

As proposed by Applicant, the project is subject to PSD preconstruction review and BACT determinations for NO_X, SO_2, and PM/PM_{10}.

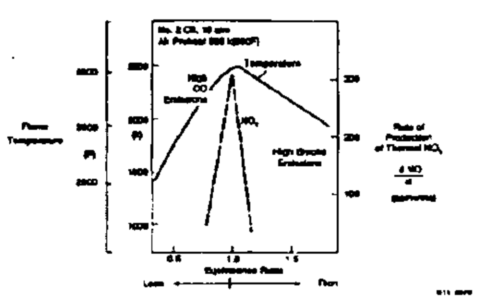
III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) – Draft Determinations

A. NITROGEN OXIDES (NO_X)

1. Discussion of NO_X Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for a GE 7FA combustion turbine.[2]

<u>Thermal NO_X</u> forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also known as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The changes in NO_X production as flame temperatures vary due to increasing/decreasing equivalence ratios can be seen in Figure 5 below.



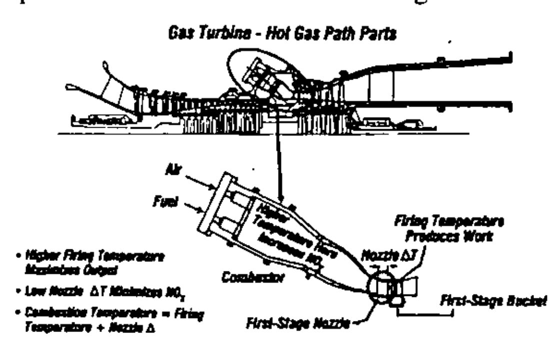


Figure 5. NO_X vs. Temperature, Equivalence Ratio.[3] **Figure 6. Hot Gas Path Parts, NO_X Control**

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 6, which is from a General Electric discussion on these principles.

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

For the purpose of further discussion, concentrations expressed in terms of ppmvd presume correction to 15% O_2 unless otherwise noted.

2. Descriptions of Available NO_X Controls

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below. During dry low-NO_X combustion while gas firing, wet injection is not employed.

Dry Low NO_X/CO (DLN) Combustion. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones. This principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in the following figure.

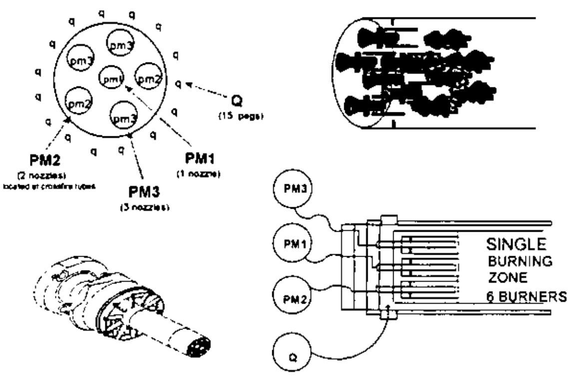
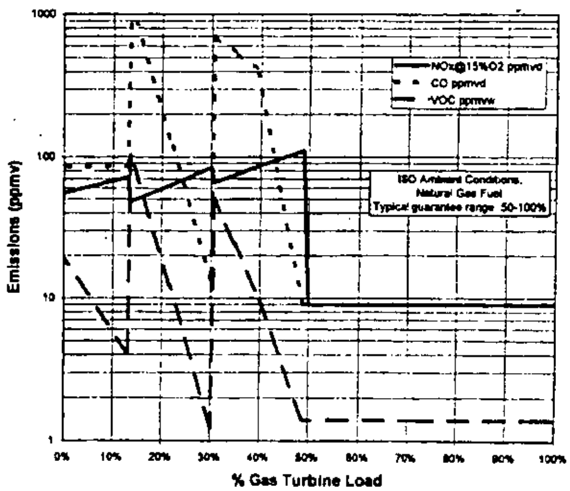


Figure 7. DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design NO_X, CO, and VOC emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 8 below for a unit tuned to meet a limit of 9 ppmvd. The values for CO are "uncorrected" for O_2. Values for VOC are uncorrected, "wet basis", and do not include methane and ethane because they are not defined as VOC.

The combustor design is such that NO_X concentrations equal 9 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. This suggests the need to minimize operation at low load conditions.



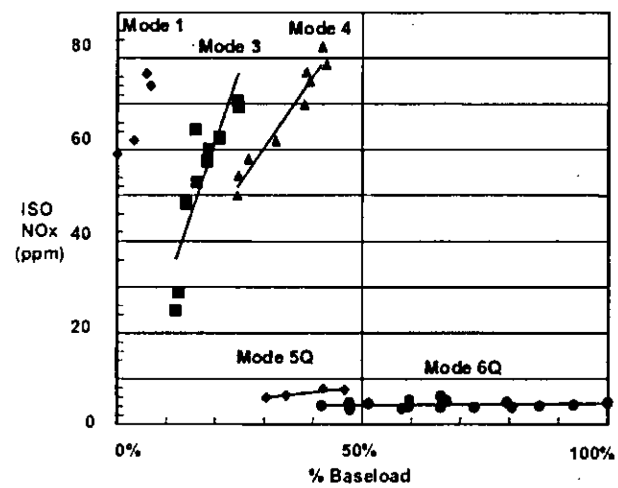


Figure 8. Design Emission Characteristics for DLN-2.6. Figure 9. NO_X Performance of DLN-2.6

Figure 9 is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility. Actual NO_X emissions are less than the design values. The Department has reviewed numerous reports and low load operation data from GE 7FA CTs in Florida and can confirm the accuracy of the graph on the right. Also actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

Table 4 summarizes the results of the new and clean tests conducted on a dual-fuel GE 7FA CT with DLN 2.6 combustors operating in simple cycle mode and burning natural gas at the existing Tampa Electric Polk Power Station.[4] The test results confirm that NO_X, CO, and VOC emissions are less than the design characteristics published by GE and given on the left hand side of the figure 8 above.

Table 4. Actual Performance of DLN-2.6 Combustors at Tampa Electric Polk Power Station.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

Numerous simple cycle GE 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions if assumed to equal 200 ppmvd.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to approximately 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

There are several examples of combined cycle SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas, 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TEC Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

More recently, DEP issued permits for the Treasure Coast Energy Center Unit 1 and FP&L Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil. The Department also required SCR on two recently constructed GE LM6000 simple cycle units at the City of Tallahassee's Hopkins facility.

SCR is a commercially available, demonstrated control technology currently employed on numerous combustion turbine projects permitted with very low NO_X emissions.

3. Applicant's NO_X BACT Proposal

The applicant eliminated several NO_X control strategies (including XONON™, Selective Non-Catalytic Reduction, Non-Selective Catalytic Reduction, and SCONOx™), based on either present technical infeasibility or unavailability for the size of CT under review. Therefore, the submitted BACT analysis was limited to DLN combustors for natural gas firing, wet injection for oil firing, and SCR as an add-on control.

Historically fuel oil usage at the Oleander site has actually been very low. The oil and gas usage from each of the four existing CTs as reported to FDEP is presented in Table 5. The percentage of allowable fuel use is based on total annual heat input and the 12-month allowable heat input adjusted for four units.

Table 5. Historical Fuel Use, Oleander Units 1, 2, 3, and 4.

YEAR	EU ID	Gas			Oil			Total Hrs Operation
		Annual Rate (mm ft^3)	Total Heat Input (mmBtu)	% of Allowable	Annual Rate (1000 Gallons)	Total Heat Input (mmBtu)	% of Allowable	
2002	1	1,395	1,295,955		795	105,002		976
	2	994	923,547		2,785	367,620		880
	3	643	597,078		522	68,950		509
	4	592	550,210		394	51,949		486
	All Units	3,624	3,366,789	14.42	4,496	593,521	7.73	2,851
2003	1	2,228	2,069,812		3,260	430,320		1,534
	2	2,267	2,106,043		1,784	235,488		1,697
	3	2,304	2,140,416		847	111,804		1,755
	4	2,065	1,918,385		1,282	169,224		1,600
	All Units	8,864	8,234,656	35.27	7,173	946,836	12.34	6,586
2004	1	1,357	1,261,099		1,545	203,990		1,106
	2	970	900,740		1,136	150,013		862
	3	817	759,337		954	125,941		681
	4	1,041	967,488		620	81,837		861
	All Units	4,186	3,888,664	16.65	4,256	561,781	7.32	3,510
2005	1	1,288	1,196,487		641	84,657		906
	2	607	564,070		1,798	237,337		576
	3	499	463,432		1,428	188,438		467
	4	236	219,309		1,457	192,327		270
	All Units	2,630	2,443,298	10.46	5,324	702,759	9.16	2,219

The column on the far right suggests that typically individual units run less than 1000 hours per year on both fuels combined. The greatest amount of fuel oil use on any unit was during 2003 on Unit 1. By proportioning the heat input for each fuel to total hours of operation, an estimate of approximately 400 hours of fuel oil firing is obtained. A similar calculation for Unit 4 during 2005 suggests approximately 130 hours of fuel oil firing. Overall, the historical use of fuel oil (even before completion of the gas expansion projects and during several hurricane seasons) at the existing units supports the adequacy of a 500 hour limit on fuel oil firing.

Typically distillate fuel oil prices are significantly greater than natural gas prices and the fuels do not typically compete within the power industry in Florida. Distillate fuel oil is only used during short-term supply interruptions and temporary natural gas price dislocations. Within the power industry, natural gas and the higher sulfur residual fuel oil (not allowed for the proposed project) do in fact compete for use in older conventional power plants.

According to a recent (July 2006) U.S. Department of Energy report, "changing market conditions in the United States over the past 7 months have led to dramatic decreases in natural gas prices from the historically high levels prevailing at the beginning of the year."[6]

According to the same report, "in the near-term, natural gas prices are expected to not be constrained unduly by residual fuel oil prices. Although natural gas prices are projected again to exceed residual fuel oil prices by the 2006-2007 winter, this historical pattern is expected to be reversed by April 2007. However, while the current trend continues, natural gas will be an economically attractive choice for electric utilities, as well as other energy customers." Here the attractiveness is in relative terms.

A similar comparison (to the natural gas/residual fuel oil comparison) between distillate fuel oil and natural gas would be even more pronounced in favor of lower relative natural gas prices. It is reasonable to conclude that natural gas will continue to be more attractive for use in combustion turbines than distillate fuel oil on the basis of price. It is also more favorable on the basis of equipment maintenance.

BACT Determination:

Considering the above discussions, the Department has made the following determination for the control of NO_X emissions from proposed Unit 5:

- NO_X emissions while firing natural gas shall be limited to 9.0 ppmvd as BACT achievable by natural gas firing and use of Dry Low NO_X combustion.
- The continuous limits for NO_X shall be based on 24-hr block averages.

Incidental Back up Fuel Oil Limits:

Back-up fuel oil use shall be limited to 500 hours per year and NO_X emissions shall be limited to 42.0 ppmvd (NSPS) achievable by injection of water into the combustors for flame cooling.

B. SULFUR DIOXIDE (SO_2)

The Department determined that BACT for NO_X is 9 ppmvd and limited the use of back-up low sulfur (0.05% sulfur) fuel oil to 500 hours per year. As a result, the potential emissions of SO_2 for the project decreased by 21.8 tons per year (TPY) from 58.9 to 37.1 TPY which is below the PSD significant threshold at which the BACT and Air Quality Analyses are required.

A BACT determination is not required for SO_2. The Department will not require use of ultra low sulfur diesel for this project.

The Department will set the following emission limits to insure that emissions from the project will be less than 40 tons per year and not trigger PSD.

- Natural gas containing no more than 1.5 grains of sulfur per 100 standard cubic feet may be fired for up to 3,390 hours per year.
- Unit 5 may be fired using low sulfur diesel fuel oil (0.05 % sulfur) for up to 500 hours of the total 3,390 allowable operating hours.

C. PARTICULATE MATTER (PM/PM_{10})

Particulate matter (PM/PM_{10}) is emitted from combustion turbines due to incomplete combustion of ash and sulfur present in the fuels. They are minimized by use of clean fuels, with low ash and sulfur contents, and good combustion practices. Clean fuels are a necessity in combustion turbines in order to avoid excessive maintenance due to damaged turbine blades and other components already exposed to very high temperatures and pressures.

The use of DLN combustor technology to maximize combustion efficiency, and the use of low ash, low sulfur fuels is proposed as BACT for PM/PM_{10}. According to the applicant, combustion efficiency is projected to be greater than 99 percent with the DLN technology. Additionally, a visible emissions limit of 10 percent opacity has been proposed as a surrogate limit for PM/PM_{10}. The Department agrees with the applicant, and the draft BACT standard for PM/PM_{10} is the proposed fuel specifications and opacity limit.

D. SUMMARY OF DEPARTMENT DRAFT BACT DETERMINATIONS

The Department establishes the following standards as the Best Available Control Technology for the simple cycle combustion turbine Unit 5 at the Oleander Power Project.

Table 6. Draft BACT Determinations – Oleander Power Project Unit 5

Pollutant	Fuel	Emission Standard/Limit[c]	Averaging Time	Compliance Method	Basis
NO_X	Gas	9.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
		62.5 lb/hr	3-hr	Stack Test	
PM/PM_{10}[a]	Gas/Oil	10 % Opacity	6-minute block	Stack Test	BACT
		1.5 gr S/100 SCF of gas/0.05 % S Oil	N/A	Record Keeping	
SO_2[b]	Gas/Oil	1.5 gr S/100 SCF of gas/0.05 % S Oil	N/A	Record Keeping	BACT Avoidance

a. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM_{10} emissions.

b. The fuel sulfur specifications effectively limit the potential emissions of SO_2 and sulfuric acid mist (SAM) from the gas turbine.

c. The mass emission rate standards are based on a turbine inlet condition of 59°F and 100 percent full load operation. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

In combination with the annual restriction of hours of operation on oil and gas, the above emissions standards effectively limit annual potential emissions from the combustion turbine to the amounts listed in the table below. The parenthetical numbers reflect the applicant's original proposal.

Table 7. Project Potential Annual Emissions Estimates after BACT and (as Proposed)

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
NO_x	174.5 (243.1)	40	Yes
SO_2	37.1 (58.9)	40	No
CO	77 (83.7)	100	No
PM	34.5 (38.5)	25	Yes
PM_{10}	34.5 (38.5)	15	Yes
VOC	11.4 (12.9)	40	No
SAM	2.7 (4.5)	7	No
Mercury	0.0006 (0.0012)	0.1	No
Lead	0.0495 (0.0489)	0.6	No
Total Fluorides	Negligible	3	No
Formaldehyde	0.655 (0.672)	NA	NA

IV. NEW SOURCE PERFORMANCE STANDARDS

A. COMBUSTION TURBINES

New stationary gas turbines are subject to the federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. This federal regulation establishes the following emission standards for new combustion turbines with a heat input at peak load of > 850 mmBtu/hr.

- NO_X (while firing natural gas) - 15 ppm @ 15 percent O_2 or 0.43 lb/ MWh
- NO_X (while firing fuels other than natural gas) - 42 ppm at 15 percent O_2 or 1.3 lb/MWh
- SO_2 - 0.90 lb/MWh gross output, or 0.060 lb SO_2/MMBtu heat input

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

V. PERIODS OF EXCESS EMISSIONS

A. EXCESS EMISSIONS PROHIBITED

In accordance with Rule 62-210.700(4), F.A.C., "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." All such preventable emissions shall be included in the compliance determinations for NO_X emissions.

B. ALLOWABLE DATA EXCLUSIONS

In accordance with Rule 62-210.700, F.A.C., "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." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest."

Operation of the General Electric Frame 7FA combustion turbine in lean premix mode is achieved at least by 50% of base load conditions. Simple cycle gas turbines are designed for quick startup and operate at high load levels. Operation of the large frame gas turbines is generally automated and malfunctions have been infrequent.

Dry Low NO_X combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions.

Based on information from General Electric regarding startup and shutdown, and the information above regarding tuning, the Department establishes the following conditions for excess emissions for the combustion turbine for which a limited amount of data may be excluded from the NO_X continuous compliance determinations.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.

- For each startup, up to 30 consecutive minutes of excess emissions may be excluded from the continuous compliance determinations.
- For each shutdown, up to 30 consecutive minutes of excess emissions may be excluded from the continuous compliance determinations.
- No more than 2 hours of CEMS data in any 24-hour period shall be excluded from compliance demonstrations due to a malfunction.
- CEMS data collected during initial or other DLN tuning sessions may be excluded from the compliance demonstrations provided that tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning sessions, the permittee shall provide the Compliance Authority with an advance notice detailing the activity and proposed tuning schedule.

VI. AIR QUALITY IMPACT ANALYSIS

A. INTRODUCTION

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: PM/PM_{10} and NO_X. PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them.

B. MAJOR STATIONARY SOURCES IN BREVARD COUNTY

The current largest stationary sources of air pollution in Brevard County are listed below. The information is from annual operating reports submitted to the Department from 2005.

Table 8. Largest Sources of PM in Brevard County

Owner	Site Name	Tons per year
Florida Power and Light	Cape Canaveral Plant	778
Reliant Energy Florida	Reliant Indian River Plant	207
Oleander Power Project	**Oleander Unit 5 (Applicant Proposal)**	**39**
R.A Connor Paving	R.A Connor Paving	28
Oleander Power Project	Oleander Power Project (Existing)	13

Table 9. Largest Sources of NOx in Brevard County

Owner	Site Name	Tons per year
Florida Power and Light	Cape Canaveral Plant	4566
Reliant Energy Florida	Reliant Indian River Plant	1295
Oleander Power Project	**Oleander Unit 5 (Applicant Proposal)**	**243**
Oleander Power Project	Oleander Power Project (Existing)	128
USAF/Cape Canaveral AFS	Cape Canaveral Air Force Station	60

C. AIR QUALITY AND MONITORING IN BREVARD COUNTY

The Florida Department of Environmental Protection Central District currently operates three monitors at two sites measuring $PM_{2.5}$ and ozone (O_3). The 2005 monitoring network is shown in the figure below. Brevard County is expected to have three additional new monitoring sites in the near future. Those monitors will be located at Atlantis Elementary School and Fay Park.

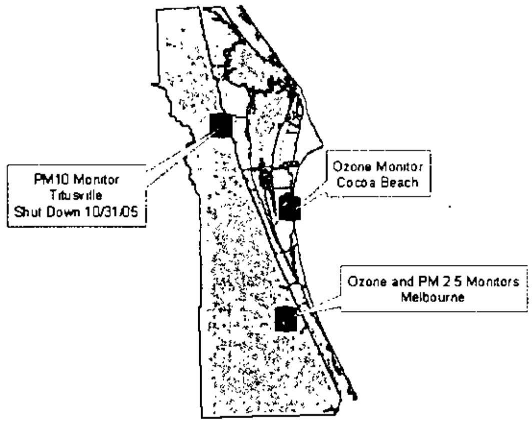


Figure 10. Brevard County Ambient Air Monitoring Network (Existing)

The following table summarizes 2005 ambient air quality data from ambient monitoring stations near the OPP project site.

Table 10. Ambient Air Quality Nearest to Project Site (2005)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Titusville	24-hour	60	48		150 [a]	ug/m^3
		Annual			15.5*	50 [b]	ug/m^3
SO_2	Orlando	3-hour	11	9		500 [a]	ppb
		24-hour	4	3		100[a]	ppb
		Annual			1	20 [b]	ppb
NO_2	Orlando	Annual			9	53 [b]	ppb
CO	Orlando	1-hour	9	8		35 [a]	ppm
		8-hour	5	3		9 [a]	ppm
Ozone	Cocoa Beach	1-hour	0.082	0.081		0.12 [C]	ppm
		8-hour	0.078	0.075		0.08 [C]	ppm

* The Mean does not satisfy summary criteria due to missing data.
a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period.

D. AIR QUALITY IMPACT ANALYSIS

1. Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10} and NO_X . A significant impact analysis is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the model. The model used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class II Area (everywhere except the designated Class I areas such as the Chassahowitzka National Wildlife Refuge).

The Class II analysis includes a combination of fence line, near-field and far-field receptors chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The near-field receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 3 kilometers. Beyond 3 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 6 kilometers from the facility. From 6 to 15 kilometers, Cartesian receptors with a spacing of 500 meters were used.

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempt from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10} and NO_X air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 11. Maximum Projected Air Quality Impacts from Oleander Unit 5 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
PM_{10}	Annual 24-Hour	0.1 1	1 5	~16 ~60	50 150	NO NO
NOx	Annual	0.3	1	~17	100	NO

Maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. PM_{10} and NOx are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Chassahowitzka National Wildlife Refuge located about 175 km to the west-northwest of the project site. According to the applicant, air quality impacts on this Class I area will be "negligible based on the distance from the project site." The Department provided this information to the U.S. Fish and Wildlife Service and they did not make any comments regarding the Class I Significant Impact Analysis specifically. However, they did state that the "Fish and Wildlife Service does not anticipate that this modification at Oleander will have significant impacts to visibility and Air Quality

Related Values at Chassahowitzka." This conclusion was based on the use of control technologies, emission rates and distance to the Class I area. Therefore, no modeling was required for the Class I area.

2. Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 12. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	1	10	~60	NO
NOx	Annual	0.3	14	~17	NO

Based on the preceding discussions, the only additional detailed air quality analysis required by the PSD regulations for this project is an analysis of impacts on soils, vegetation, and of past growth-related air quality effects.

3. Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA November 2005 and will officially replace the ISCST3 model November 2006. During this "transition" time period from November 2005 to November 2006, both the ISCST and AERMOD model may be used. This "transition" will allow applicants and the Department assimilate AERMOD guidance and procedures.

The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant and the Department used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The modeling submitted with the application included an AERMET file created by the applicant. The meteorological data consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at Orlando International Airport and Tampa/Ruskin respectively. The 5-year period of meteorological data was from 1996 through 2000. These airport stations were selected for use in the study because they are most representative of the project site.

Along with National Weather Service data, the AERMET processor requires an input of surface parameters based on land use. These characteristics include albedo, surface roughness and bowen ratio. The Department is currently creating a series of AERMET files for National Weather Service stations in Florida. Due to the variations in surface parameter values, by using uniform data sets created by one entity, the Department will ensure continuity from project to project. The data created by the Department for Orlando

International Airport and Tampa/Ruskin was completed after the application for Unit 5 was received. Therefore, the Department modeled Unit 5 with this data to verify the applicant's results.

The Department AERMET data consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at Orlando International Airport and Tampa/Ruskin respectively. However, the 5-year period of meteorological data was from 1999-2003. The results of the Significant Impact Analysis listed above are indicative of the highest concentrations modeled with both data sets.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

E. ADDITIONAL IMPACTS ANALYSIS

1. Impact on Soils, Vegetation, and Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10} and NO_X as a result of the proposed project, including background concentrations will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10} and NO_X, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

2. Impact on Visibility and Air Quality Related Values (AQRV) in the Class I Area

As mentioned previously, the Fish and Wildlife Service does not anticipate that this modification at Oleander will have significant impacts to visibility and Air Quality Related Values (rates of nitrogen deposition) at the Chassahowitzka based on the use of control technologies, emission rates and distance to the Class I area.

3. Growth-Related Impacts Due to the Proposed Project

Increases in the labor force are not expected due to this project. Commercial and residential growth will not occur. Therefore, there will be no adverse air impacts due to growth from this project.

4. Growth-Related Air Quality Impacts since 1977

According to the applicant, population growth in the area of the proposed project, Brevard County, has nearly doubled from 1980 to 2000, growing to 470,000 from approximately 275,000. Brevard growth corresponds with Florida growth. According to the City of Palm Bay, Palm Bay grew in excess of 200% in the 1980's and is the ninth fastest growing Florida city.

Despite the population growth and obvious increases in vehicular traffic, Brevard County has remained in attainment with the Ambient Air Quality Standards. For example, for the pollutant ozone, the Air Quality Index (which reports daily air quality) from 2000-2003 was "Good" for 96.4%, "Moderate" for 3.3% and "Unhealthy for Sensitive Groups" for 0.3% of the days over the 3-year period. There were no "Generally Unhealthy" or "Very Unhealthy" days.

VII. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Cindy Mulkey is the project review engineer and is responsible for preparing the draft permit. She may be contacted at cindy.mulkey@dep.state.fl.us and 850-921-8968. Debbie Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537.

REFERENCES

1 Manual. EPA, Office of Air Quality Planning and Standards, "DRAFT New Source Review Workshop Manual", October 1990.

2 Technical Report GE 3695E. Badeer, G. H., General Electric. "GE Aeroderivative Gas Turbines – Design and Operating Features." 2000.

3 Technical Report GE Power Systems GER 3568G. Davis, L. B., and S.H. Black, General Electric. "Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines." 2000.

4 Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TEC Polk Power Station." September 2000.

5 Report to Legislature. California Environmental Protection Agency, Air Resources Board. Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts. May 2004.

6 Energy Information Administration, Department of Energy, Natural Gas Weekly Update, July 7, 2006.

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Oleander Power Project	
Simple Cycle Unit 5	
Permit No.	PSD-FL-377
Project No.	0090180-003-AC
Expires:	June 1, 2008

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 190 MW simple cycle combustion turbine electrical generator at the existing Oleander Power Project. The facility is located in Cocoa just off Interstate 95 and State Road 520 in Brevard County.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

DRAFT
Joseph Kahn, P.E., Acting Director
Division of Air Resource Management

FACILITY DESCRIPTION

The regulated emissions units at the existing Oleander Power Project include four nominal 190 MW simple cycle combustion turbines (Units 001 through 004) capable of firing either natural gas or low-sulfur fuel oil (0.05 percent sulfur), and two 1.8 million-gallon fuel oil storage tanks (Units 006 and 007).

PROJECT DESCRIPTION

The project is for the construction of one additional General Electric PG7241(FA) simple cycle combustion turbine electrical generator (Unit 5) equipped with evaporative cooling, capable of firing natural gas, with a nominal output of 190 megawatts. The project also includes the installation of one 900,000 gallon distillate fuel oil storage tank. Low sulfur fuel oil will be used as a backup fuel to the combustion turbine.

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU ID NO.	EMISSION UNIT DESCRIPTION
005	Unit 5 - Consists of one General Electric PG7241 FA gas turbine electrical generator (nominal 190 MW) equipped with evaporative inlet air cooling.
008	Unit 8– One 900,000 gallon distillate fuel oil storage tank.

REGULATORY CLASSIFICATION

Title I, Part C, Clean Air Act (CAA): The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

Title I, Section 111, CAA: Unit 5 is subject to the New Source Performance Standards of 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).

Title I, Section 112, CAA: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV, CAA: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, CAA: The facility is a Title V or "Major Source of air pollution" in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

CAIR: As an electric generating unit, Unit B may be subject to the Clean Air Interstate Rule pending the finalization of DEP rules.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

SECTION I - GENERAL INFORMATION

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Central District, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	NSPS Subparts A, Identification of General Provisions
Appendix BD	Final BACT Determinations and Emissions Standards
Appendix GC	General Conditions
Appendix KKKK	NSPS Subpart KKKK Requirements for Stationary Combustion Turbines
Appendix SC	Standard Conditions

RELEVANT DOCUMENTS:

The documents listed below are not a part of this permit, however they are specifically related to this permitting action and are on file with the Department.

- Application for Air Construction Permit received on May 4, 2006;
- Department's Request for Additional Information dated June 2, 2006;
- Applicant's Response to Request for Additional Information Received July 13, 2006 (complete);
- Department's Intent to Issue and Public Notice Package distributed September 12, 2006;
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(12), F.A.C.]

4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

5. Source Obligation.

   a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

6. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. This permit authorizes construction of the referenced facilities. [Chapters 62-210 and 62-212, F.A.C.]

7. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

8. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Unit 5 Simple Cycle Combustion Turbine (EU 005)

The specific conditions of this subsection apply to the following emissions unit after construction is complete.

E.U. ID	Emission Unit Description
005	Unit 5 - Consists of one General Electric PG7241 FA gas turbine electrical generator (nominal 190 MW) equipped with evaporative inlet air cooling.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: A determination of the Best Available Control Technology (BACT) was made for nitrogen oxides (NO_X), and particulate matter (PM/PM_{10}). [Rule 62-210.200 (BACT), F.A.C.]

2. NSPS Requirements: This unit shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Gas Turbines). See Appendix A and Appendix KKKK of this permit. The BACT emissions standards for NO_X and the fuel sulfur specifications for PM/PM_{10} are as stringent as, or more stringent than the NO_X and SO_2 limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts.
[Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60, Subparts A and KKKK]

EQUIPMENT DESCRIPTION

3. Combustion Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 190 MW. The combustion turbine will be equipped with GE's DLN combustor, and an inlet air filtration system with evaporative coolers. The combustion turbine will be designed for operation in simple cycle mode and will have dual-fuel capability. [Application; Design]

CONTROL TECHNOLOGY

4. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for NO_X. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.
[Design; Rule 62-212.400(10)(BACT), F.A.C.]

5. Wet Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the combustion turbine when firing distillate fuel oil. Prior to the initial emissions performance tests, the water injection system shall be tuned to achieve sufficiently low NO_X values to meet the NO_X limits of this permit. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Applicant request; Rule 62-212.400(10)(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

6. Hours of Operation: The combustion turbine may operate no more than 3,390 hours per calendar year. Restrictions on individual methods of operation are specified in separate conditions.
[Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

7. Permitted Capacity: The nominal heat input rate to the combustion turbine is 1,721.9 MMBtu per hour when firing natural gas and 1,919.5 MMBtu per hour when firing fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that

correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Rule 62-210.200(PTE), F.A.C.]

8. Authorized Fuels: The combustion turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.5 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the combustion turbine may fire low sulfur fuel oil containing no more than 0.05% sulfur by weight. The gas turbine shall fire no more than 500 hours of fuel oil, during any calendar year.
[Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD, and PSD Avoidance), F.A.C.]

9. Simple Cycle, Intermittent Operation: The turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built.
[Rules 62-212.400(12) and 62-212.400(BACT), F.A.C.].

EMISSIONS AND TESTING REQUIREMENTS

10. Emission Standards: Emissions from the combustion turbine shall not exceed the following standards.

Pollutant	Emission Standard [c]	Averaging Time	Compliance Method	Basis
NO_X (Gas)	9.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
	62.5 lb/hr	3 1-hr runs	Stack Test	
NO_X (Oil)	42.0 ppmvd @ 15% O_2	24-hr block	CEMS	NSPS
	336.8 lb/hr	3 1-hr runs	Stack Test	
PM/PM_{10} [a]	10 % Opacity	6-minute block	Visible Emissions Test	BACT
	1.5 gr S/100 SCF of gas/ 0.05 % S fuel oil	N/A	Record Keeping	
SO_2 [b]	1.5 gr S/100 SCF of gas/ 0.05 % S fuel oil	N/A	Record Keeping	PSD Avoidance

a. The fuel sulfur specifications combined with the efficient combustion design and operation of the combustion turbine represent BACT for PM/PM_{10} emissions. Compliance with the visible emissions standard shall serve as an indicator of good combustion.

b. The fuel sulfur specifications and limited hours of operation effectively limit the potential emissions of SO_2 and sulfuric acid mist (SAM) from the gas turbine.

c. The mass emission rate standards are based on a turbine inlet condition of 59°F and 100 percent full load operation. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from the combustion turbine to: 174.5 tons/year of NO_X, 34.5 tons/year of PM/PM_{10}, and 37.1 tons/year of SO_2.}

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD and PSD Avoidance), F.A.C]

11. Nitrogen Oxides (NO_X): Emissions of NO_X from the CT shall not exceed the following standards on a continuous basis and as measured by the required CEMS for the averaging period specified, and as measured during the required stack tests.

    a. *While firing natural gas:*

        9 ppmvd @ 15% O_2 on a 24-hr block average (CEMS)

        62.5 /lb/hr (3 1-hr run stack test)

    b. *While firing fuel oil:*

        42.0 ppmvd @ 15% O_2 on a 24-hr block average (CEMS)

        336.8 lb/hr (3 1-hr run stack test)

    [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

12. Sulfur Dioxide (SO_2):

    a. *While firing natural gas*: The fuel sulfur specifications, established in condition 8 of this subsection, of 1.5 grains per 100 standard cubic feet effectively limit the potential emissions of SO_2 from the combustion turbine while firing natural gas.

    b. *While firing fuel oil*: The fuel sulfur specification, established in condition 8 of this subsection, of 0.05 % sulfur by weight effectively limit the potential emissions of SO_2 from the combustion turbine while firing fuel oil.

    [Rules 62-4.070(3), and 62-212.400 (PSD Avoidance), F.A.C]

13. Particulate Matter (PM/PM_{10}): The fuel sulfur specifications, established in condition 8 of this subsection, combined with the efficient combustion, design, and operation of the combustion turbine represent BACT for PM/PM10 emissions. Compliance with the fuel specifications and visible emissions standard shall serve as indicators of good combustion. Visible emissions shall not exceed 10 % opacity as observed during the required visible emissions tests.

    [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

14. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

15. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of NOx Emissions (Instrumental).
9	Visual Determination of Opacity
20	Determination of NOx, SO_2, and Diluent Emissions from Stationary Gas Turbines

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

16. Testing Requirements: Initial tests shall be conducted between 90% and 100% of permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. Subsequent annual tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. Tests shall be conducted for each pollutant while firing each fuel in the CT. For each run during tests for visible emissions, emissions of NO_X recorded by the CEMS shall also be reported. Data collected from the reference method during the required CEMS quality assurance RATA tests may substitute for annual compliance tests for NO_X, provided the owner or operator indicates this intent in the submitted test protocol, and obtains approval prior to testing. [Rule 62-297.310(7)(a), F.A.C.; 40 CFR 60.8]

17. Initial Compliance Demonstration: Initial compliance stack tests while firing natural gas shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after the initial startup. Initial testing on fuel oil shall be conducted within 60 days of any fuel oil firing in the CT. In accordance with the test methods specified in this permit, the combustion turbine shall be tested to demonstrate initial compliance with the emission standards for NO_X and with the visible emissions standard. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees. [Rules 62-4.070, 62-297.310(7)(a), F.A.C. and 40 CFR 60.8]

18. Subsequent Compliance Testing: Annual compliance tests for NO_X, and visible emissions shall be conducted during each federal fiscal year (October 1st, to September 30th). If normal operation on fuel oil is less than 400 hours per year, then subsequent compliance testing on fuel oil is not required for that year. If normal operation on fuel oil exceeds 400 hours per year, the Department shall require compliance testing for NO_X and visible emissions while firing fuel oil. [Rules 62-4.070, 62-210.200(BACT), and 62-297.310(7)(a)4, F.A.C.]

19. Continuous Compliance: Continuous compliance with the permit standard for emissions of NO_X shall be demonstrated with data collected from the required continuous monitoring system. [Rules 62-4.070, and 62-210.200(BACT), F.A.C.]

20. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No 10 and 11 of this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the combustion turbine in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

22. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

    [Rule 62-210.200(165, 242, and 258), F.A.C.]

23. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

24. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS emissions data, as specified in condition 25, may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to, the duration of data excluded is minimized, and the procedures for data exclusion listed below are followed. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    b. *Event Driven Exclusion.* There must be an underlying event (startup, shutdown, or malfunction) in order to exclude data. If there is no underlying event, then no data may be excluded.

    c. *Continuous Exclusion.* Data shall be excluded on a continuous basis. Data from discontinuous periods shall not be excluded for the same underlying event.

    [Rule 62-210.700 F.A.C.]

25. Allowable Data Exclusions: The following data may be excluded from the corresponding SIP-based compliance demonstration for each of the events listed below in accordance with the Data Exclusion Procedures of condition 24:

    a. *Startup:* Up to 30 minutes of CEMS data may be excluded for each combustion turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup may be excluded.

    b. *Shutdown:* Up to 30 minutes of CEMS data may be excluded for each combustion turbine shutdown. For shutdowns of less than 30 minutes in duration, only those minutes attributable to shutdown may be excluded.

    c. *Malfunction*: Up to two hours (in any calendar day) of CEMS data may be excluded due to a documented malfunction. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic email.

    d. *DLN Tuning*: CEMS data collected during initial or other DLN tuning sessions shall be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning session, the permittee shall provide the

Compliance Authority with an advance notice of at least one (1) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report emissions for the Annual Operating Report.

[Rules 62-210.200(BACT), 62-210.370, and 62-210.700, F.A.C.]

26. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. [Rule 62-4.070, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

27. CEM Systems: Subject to the following, the permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) to measure and record the emissions of NO_X from the combustion turbine in terms of the applicable standards. The monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.

    a. *NO_X Monitor:* Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    b. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where NO_X is monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    [Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60, Subpart 75]

28. Moisture Correction: If necessary, the owner or operator shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-4.070(3), 62-210.200(BACT), F.A.C]

29. CEMS Data Requirements for BACT Standards:

    {Permitting Note: The following conditions apply only to the SIP-based NO_X emissions standards specified in Condition Nos. 10-11 of this section. These requirements cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs. Additional reporting and monitoring may be required by the individual subparts.}

    a. *Data Collection*: Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions shall be monitored and recorded during all operation including startup, shutdown, and malfunction.

    b. *Operating Hours and Operating Days*: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. *Valid Hour*: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

   1) Hours that are **not operating** hours are **not valid** hours.
   2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid.
   3) During fuel switching an hour in which fuel oil is fired is attributed towards compliance with the permit standards for oil firing.

d. *Block 24-Hour Average:* A 24-hour block shall begin at midnight of each operating day and compliance shall be determined by calculating the arithmetic average of all valid hourly averages occurring within that 24-hr block. If a unit operates less than 24 hours during the block, or there are less than 24 valid hourly averages available, the block average shall be the average of all available valid hourly average concentration values during that 24-hr block.

e. *Missing Data/Bias Adjustments:* If the owner or operator has installed a CEMS to meet the requirements of Part 75, data reported to show compliance with any SIP-based limit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

f. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, DLN tuning, and fuel switches. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of conditions 24 and 25 of this subsection.

g. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

CEMS REQUIREMENTS FOR ANNUAL EMISSIONS

30. CEMS Annual Emissions Requirement: The owner or operator shall use data from the NO_X CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C.

31. CEMS Data Used for Annual Emissions Calculation: All valid data, as defined in Condition 29, shall be used when calculating annual emissions.

   a) Annual emissions shall include data collected during periods of startup, shutdown, malfunction, and DLN tuning.
   b) Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control

activity such as calibration error tests, RATAs, calibration gas audits, or RAAs. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

c) Annual emissions shall not include data form periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

32. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hr block average that begins at the top of each hour. For each hour, the 1-hr block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hr block average.

33. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hr block average and duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

34. Acid Rain CEMS: For CEMS that are also subject to the Acid Rain Program, the data substitution and bias adjustment procedures from 40 CFR Part 75 shall only be applied to data submitted to the U.S. EPA. Annual emissions shall be determined using unadjusted data and using the calculation procedures of the preceding conditions of this permit.

REPORTING AND RECORD KEEPING REQUIREMENTS

35. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

36. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the combustion turbine for the previous month of operation: fuel consumption, hours of operation, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

37. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of the Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

38. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

39. Excess Emissions Reporting:

a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NO_X emissions in excess of the BACT permit standard following the NSPS format in 40 CFR 60.7(c), Subpart A. A summary of data excluded from SIP compliance calculations should also be provided. In addition, the report shall summarize the NO_X CEMS system monitor availability for the previous quarter.

c. *NSPS Reporting*: Within 30 days following the calendar quarter, the permittee shall submit the written reports required by 40 CFR 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) for the previous quarter or semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C., and 40 CFR 60.7 and 60.4375]

40. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with 62-210.370. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. Fuel Oil Storage Tank (EU 008)

ID	Emission Unit Description
008	Unit 8– One 900,000 gallon distillate fuel oil storage tank.

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil storage tank is not subject to Subpart Kb which applies to storage vessels with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 151 cubic meters (40,000 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 008) has a capacity greater than 151 cubic meters and the vapor pressure of the low sulfur fuel oil is less than 3.5 kPa, therefore NSPS Kb, including the monitoring requirements, does not apply to this unit.
[40 CFR 60.110b(a) and (b), and 60.116b(c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 900,000 gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to the Unit 5 gas turbine.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year).
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for use in the Annual Operating Report.
[Rule 62-204.800(7)(b)16, F.A.C]

5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. If the maximum true vapor pressure of the stored liquid exceeds 3.5 kPa, the Unit 8 storage tank shall be subject to the applicable requirements of Subpart Kb. [62-4.070(3) F.A.C.]

SECTION IV. APPENDICES

CONTENTS

NSPS Subpart A, Identification of General Provisions

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

The Department establishes the following standards as the Best Available Control Technology for the simple cycle combustion turbine Unit 5 at the Oleander Power Project.

BACT Determinations – Oleander Power Project Unit 5

Pollutant	Fuel	Emission Standard/Limit[c]	Averaging Time	Compliance Method	Basis
NO_X	Gas	9.0 ppmvd @ 15% O_2	24-hr block	CEMS	BACT
		62.5 lb/hr	3-hr	Stack Test	
PM/PM_{10}[a]	Gas/Oil	10 % Opacity	6-minute block	STACK TEST	BACT
		1.5 gr S/100 SCF of gas/0.05 % S Oil	N/A	RECORD KEEPING	
SO_2[b]	Gas/Oil	1.5 gr S/100 SCF of gas/0.05 % S Oil	N/A	Record Keeping	BACT Avoidance

a. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions.

b. The fuel sulfur specifications effectively limit the potential emissions of SO2 and sulfuric acid mist (SAM) from the gas.

c. The mass emission rate standards are based on a turbine inlet condition of 59°F and 100 percent full load operation. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emssion Standards for Hazardous Air Pollutants (Not Applicable); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

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

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART KKKK REQUIREMENTS FOR STATIONARY COMBUSTION TURBINES

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NOX) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOX emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOX) and sulfur dioxide (SO2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NOX specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOX.

§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NOX emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOX monitor and a diluent gas (oxygen (O2) or carbon dioxide (CO2)) monitor, to determine the hourly NOX emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NOX emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOX emission result from the performance test is less than or equal to 75 percent of the NOX emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOX emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOX formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode.

(iii) For any turbine that uses SCR to reduce NOX emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOX CEMS is chosen:

(a) Each NOX diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOX diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NOX monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOX emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOX and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOX emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOX concentrations to 15 percent O2 is not allowed.

(d) If you have installed and certified a NOX diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NOX emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NOX emission rate, in lb/MWh, (NOX)h = hourly NOX emission rate, in lb/MMBtu, (HI)h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)t = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NOX emission rate in lb/MWh,

(NOX)m = NOX emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep onsite a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOX emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NOX emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping onsite (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustionfuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in§60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for units located in continental areas and 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas or 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur samplingschedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes ofthis subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NOX control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4- hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOX emission rate" is the arithmetic average of all hourly NOX emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOX emissions rates for the preceding 30 unit operating days if a valid NOX emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOX concentration, CO2 or O2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NOX limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NOX limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NOX performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOX concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NOX emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NOX emission rate, in lb/MWh

1.194 × 10–7 = conversion constant, in lb/dscf-ppm

(NOX)c = average NOX concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NOX and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOX emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NOX emission rate in lb/MWh.

(2) Sampling traverse points for NOX and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multihole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO2 (or O2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NOX concentration during the stratification test; or

(B) For turbines with a NOX standard greater than 15 ppm @ 15% O2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOX standard less than or equal to 15 ppm @ 15% O2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOX concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO2 (or O2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NOX emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NOX with no additional post-combustion NOX control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NOX emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOX emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NOX-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOX emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NOX emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO2 emission rate, in lb/MWh

1.664 × 10−7 = conversion constant, in lb/dscf-ppm

(SO2)c = average SO2 concentration for the run, in ppm

Qstd = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the SO2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NOX emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation. *ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coalderived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1_to Subpart KKKK of Part 60_Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating	[le] 50 MMBtu/h...	42 ppm at 15. percent O2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive.	[le] 50 MMBtu/h...	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/ MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h...	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/ MWh)
New turbine firing fuels other than natural gas, electric generating	[le] 50 MMBtu/h...	96 ppm at 15 percent O2 or 700 ng/J of useful output (5.5 lb/ MWh).
New turbine firing fuels other than natural gas, mechanical drive.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and [le] 850 MMBtu/h	74 ppm at 15 percent O2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than	> 850 MMBtu/h...	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3

natural gas.		lb/MWh).
Modified or reconstructed turbine.	[le] 50 MMBtu/h...	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h.	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/ MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and [le] 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F.	[le] 30 MW output.	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output.	96 ppm at 15 percent O2 or 590 ng/J of useful 75 output (4.7 lb/ MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes.........	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MWh).

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: 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.]

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

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. 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 two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the 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. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, 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.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. 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. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: 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. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. <u>Records Retention</u>: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A

Memorandum

Florida Department of Environmental Protection

TO: Trina L. Vielhauer

THROUGH: A.A. Linero *aal*

FROM: Cindy Mulkey *cem*

DATE: September 8, 2006

SUBJECT: Oleander Power Project, L.P. – Simple Cycle Combustion Turbine
DEP File No. 0090180-003-AC (PSD-FL-377)

Attached is the draft permit package for construction of a 190 megawatt GE 7FA simple cycle combustion turbine (Unit 5) at the existing Oleander Power Project (OPP) owned and operated by affiliates of Southern Company. The rating of 190 MW is the nominal low temperature rating. These units are typically rated at 170 MW at ISO conditions.

The OPP facility is located in Cocoa, Brevard County.

The new construction also includes a 60-foot exhaust stack and a nominal 900,000 gallon fuel oil storage tank. The facility was originally permitted to construct five GE 7FA simple cycle CTs and two fuel oil storage tanks. However, only four of the CTs and the two authorized fuel oil storage tanks were actually constructed.

The new CT will be capable of firing either natural gas or low sulfur fuel oil (0.05 percent sulfur). Unit 5 will be permitted to operate a total of 3,390 hours per year with a maximum of 500 hours of fuel oil firing.

Unit 5 triggered PSD and a BACT determination for NO_X, and PM/PM10. The BACT for NO_X is 9 ppmvd. The actual control is by Dry Low NO_X combustors and use of natural gas. A limit of 42 ppmvd applies while burning backup distillate fuel oil. Control will be achieved by wet injection.

We recommend your approval of the attached package for public distribution.

AAL/cem

Attachments