Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North JK

DATE: March 6, 2006

SUBJECT: Draft Air Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination (with BACT Determination);
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is March 6, 2006. I recommend your approval of the attached Draft Permit for this project.

Attachments

March 6, 2006

Mark J. Hornick, General Manager
Tampa Electric Company – Polk Power Station
PO Box 111
Tampa, Florida 33601-0111

Re: Draft Air Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5

Dear Mr. Hornick:

The Tampa Electric Company applied for a PSD air construction permit to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Jeff Koerner, at 850/894-4912.

Sincerely,

Jeffery J. Koerner
For Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Polk County, Florida

Facility Location: The Tampa Electric Company operates the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

Project: The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 megawatts each at the existing power plant. The new peaking units will fire only natural gas and will be restricted to 4380 hours per year of operation. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comments received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 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 Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting

Authority at the above address or phone number. If comments received result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact; (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 the 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 Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Jeffery J. Koerner

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/6/06 to the persons listed below.

Mark J. Hornick, TECO*
Byron T. Burrows, TECO
Raisa Calderon, TECO
Tom Davis, ECT
Jason Waters, Southwest District Office
Hamilton Oven, DEP Siting Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

[signature] 3/6/06
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1050233-018-AC / Draft Air Permit No. PSD-FL-363
Tampa Electric Company – Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5
Polk County, Florida

Applicant: The applicant for this project is the Tampa Electric Company. The applicant's authorized representative and mailing address is: Mark J. Hornick, General Manager; Tampa Electric Company – Polk Power Station; PO Box 111; Tampa, Florida 33601-0111.

Facility Location: The Tampa Electric Company operates the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

Project: The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 megawatts each at the existing power plant. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. Total potential annual project emissions will be: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.

In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions. The Department made the following draft determinations of the Best Available Control Technology (BACT): NOx emissions will be controlled by the efficient dry low-NOx combustion design of the General Electric gas turbines and the exclusive firing of natural gas; PM/PM_{10} emissions will be minimized by the exclusive firing of natural gas and the efficient combustion design; and SO_2 emissions will be minimized by the exclusive firing of natural gas, which contains almost negligible amounts of sulfur. In addition, CO and VOC emissions will be minimized by the efficient combustion of natural gas. CO and NOx emissions from each gas turbine will be continuously monitored and recorded.

Based on the applicant's air quality modeling analysis, the maximum predicted air quality impacts due to emissions from the proposed project will be less than the applicable PSD Class II significant impact levels. Therefore, a multi-source modeling analysis is not required. Also, the maximum predicted impacts in the Chassahowitzka National Wilderness Area will be less than the applicable PSD Class I significant impact levels. Therefore, a multi-source Class I PSD increment modeling analysis is not required. The applicant has provided the Department with reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If comments received result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. PSD-FL-363
Project No. 1050233-018-AC

Tampa Electric Company
Polk Power Station

Two New Simple Cycle Gas Turbines
Nominal 165 MW Each

COUNTY

Polk County, Florida

APPLICANT

Tampa Electric Company
9995 State Route 37 South
Mulberry, Florida 33860-0775

PERMITTING AUTHORITY

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

March 6, 2006

1. APPLICATION INFORMATION

Facility Location

The Polk Power Station is located approximately 11 miles south of the city of Mulberry on State Route 37 in Polk County. The site is 120 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 402.45 km East and 3067.35 km North. The locations of Mulberry and the Polk Power Station are shown below.

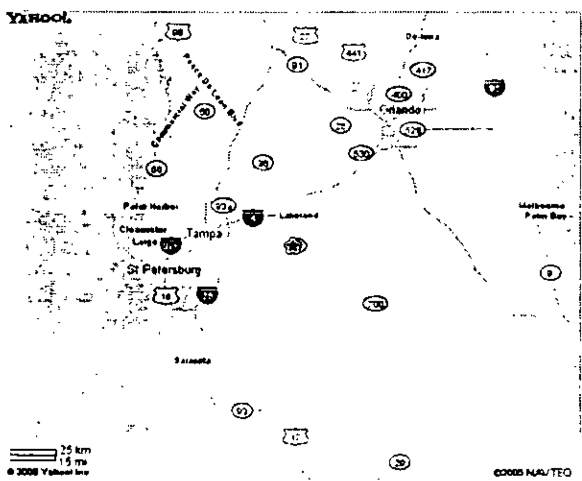

Figure 1.1 Location of Mulberry

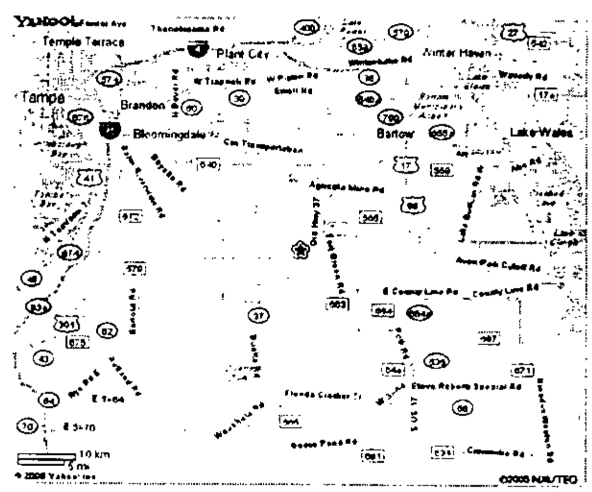

Figure 1.2 Location of Polk Power Station

Facility Description

The Polk Power Station is an existing electrical power generating plant (SIC No. 4911). The regulated emissions units include: a 260 MW integrated coal gasification and combined cycle gas turbine (Unit 1) that fires synthetic gas (syngas) or No. 2 fuel oil; an auxiliary boiler that fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and two nominal 165 MW simple cycle gas turbines (Units 2 and 3) that fire natural gas or No. 2 fuel oil.

Regulatory Categories

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

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

Title V: The facility is a Title V or "major source" of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

NSPS: Units 4 and 5 are subject to 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). They are not be subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005) because the purchase contract with General Electric was signed on July 21, 2000, which is prior to the NSPS effective date.

NESHAP: Units 4 and 5 are not subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) because the facility is not a major source of HAPs.

Siting: This plant is subject to certain requirements of Chapter 403, Part II, Florida Statutes, Electric Power Plant and Transmission Line Siting, including a modification of the conditions Site Certification PA92-32.

Processing Schedule

- Application for air construction permit received on October 18, 2005;
- Addendum to application for air construction permit received October 24, 2005;
- Department's request for additional information dated November 17, 2005;
- Applicant's response to request for additional information received December 23, 2005; complete.

Project Description

At the existing facility, the applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators, each with a nominal output of 165 MW. Each unit may operate up to 4380 hours per year. The new units will be fired exclusively with natural gas which will minimize SO_2 emissions. The units will be constructed using dry low-NO_X burner technology for the control of NO_X emissions and advanced burner design with good operating practices to minimize incomplete combustion and CO, PM_{10}, and VOC emissions. Figure 1.3 identifies the key components of the GE MS 7001 FA, a predecessor of the PG 7241(FA).

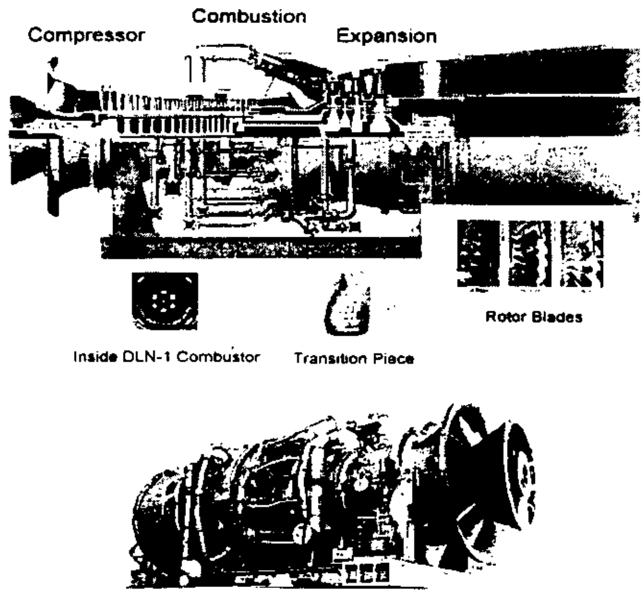

Figure 1.3 Internal and External Views of Early GE 7FA

At an ambient temperature of 59° F and 100% load, the maximum heat input rate to each gas turbine is 1834 MMBtu per hour (HHV). Each unit will have a stack that is 114 feet tall with an exit diameter of 18 feet. Exhaust gases will exit the stack at 1117° F with a flow rate of 2,393,587 acfm.

Process Description

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

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 where it is compressed by a pressure ratio of about 15 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. Flame temperatures in a typical combustor section can reach 3600° F. Units such as the 7FA operate at lower flame temperatures to 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% 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. The gas turbine exhaust is discharged at a temperature greater than 1000° F with excess oxygen and is available for additional energy recovery.

2. RULE APPLICABILITY

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
62-17	Electrical Power Plant Siting
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

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	New Source Performance Standards (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.

PSD Preconstruction Review Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) of Air Quality program, as defined in Rule 62-212.400, F.A.C. A PSD preconstruction 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" such pollutants. A PSD-major facility is one that 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 facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates identified in Rule 62-210.200(243), F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it is required to install BACT controls for each "PSD-significant" pollutant. In accordance with Rule 62-212.400(4), F.A.C., 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 and 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 is defined in Rule 62-210.200(38), F.A.C. 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 the 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 case-by-case BACT determinations in accordance with the requirements given above. Additionally, the Department generally conducts such reviews so that the determinations are consistent with those conducted using the "Top-Down Methodology" described by EPA.[1]

In addition to the required BACT determinations, a PSD preconstruction review also requires an Air Quality Analysis for each PSD-significant pollutant. The Air Quality Analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of predicted project concentrations with the National Ambient Air Quality Standards (NAAQS) and PSD increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

PSD Applicability for the Project

The project will result in emissions of carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), volatile organic compounds (VOC), and lead. In the original application, the applicant proposed 750 operating hours of firing distillate oil in addition to the 4380 hours of firing natural gas for each gas turbine. The applicant later withdrew the request to fire distillate oil. The following table summarizes the annual potential emissions in tons per year (TPY) based on the applicant's proposed emissions standards and excluding distillate oil firing.

Table 2A. Applicant's Estimated Potential Annual Emissions

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rates (TPY)	PSD Review Required?
NO_x	267	40	**Yes**
SO_2	42	40	**Yes**
CO	99	100	No
PM	79	25	**Yes**
PM_{10}	79	15	**Yes**
VOC	12	40	No
SAM	5	7	No
Mercury	N/A	0.1	No
Lead	0.125	0.6	No

Based on the above estimated annual emissions, the project is subject to PSD preconstruction review for the following pollutants: NOx, SO_2, and PM/PM_{10}.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) - DRAFT DETERMINATIONS

Nitrogen Oxides (NO_X)

Discussion of NOx Emissions

Nitrogen oxides form during the combustion process in a gas turbine 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 gas turbine.[2] There are three primary mechanisms of NOx formations: thermal NOx, prompt NOx, and fuel NOx.

Thermal NO_X 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 3.1. 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 3.2, 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.

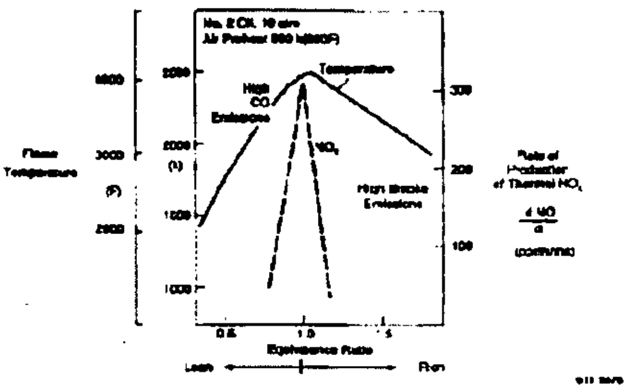

Figure 3.1 CO and NO_X vs. Flame Temperature[3]

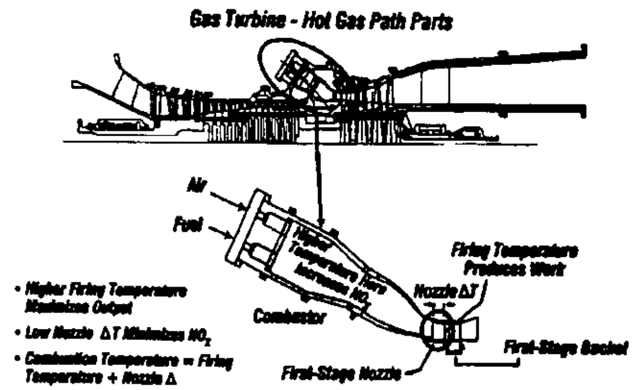

Figure 3.2 Flame Temperature and Firing Temperature

Available NOx Controls

Dry Low NO_X (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 Figure 3.3.

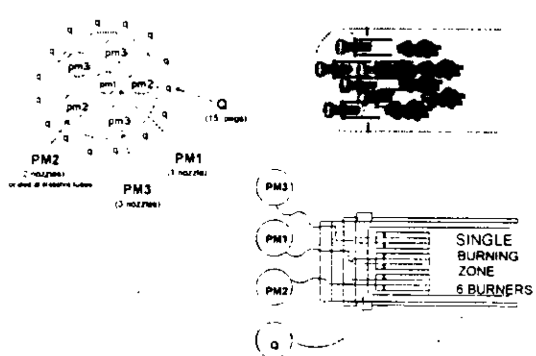

Figure 3.3 DLN-2.6 Fuel Nozzle Arrangement

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 the graph on the left side of Figure 3.4 for a unit tuned to meet a 9 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen). The graph on the right hand side is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility.

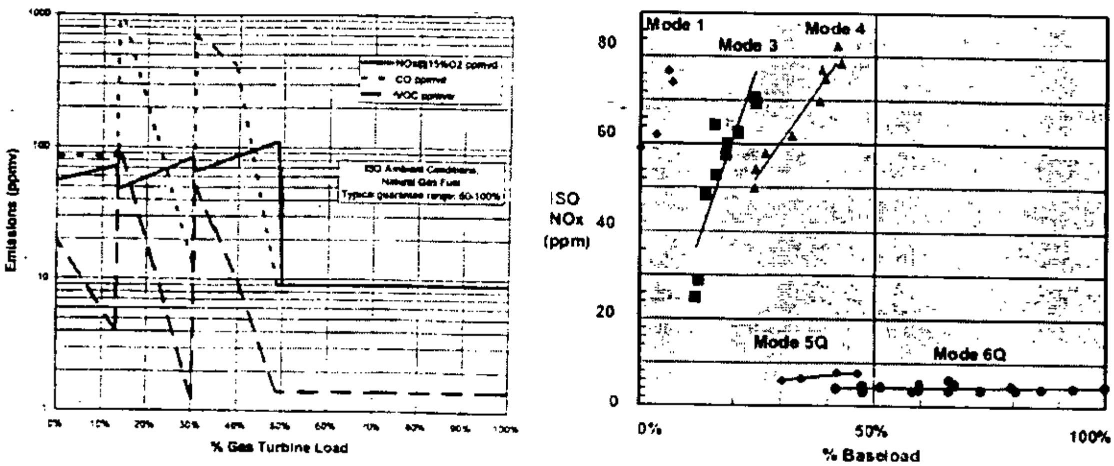

Figure 3.4 Emissions Characteristics for DLN-2.6

The combustor emits NO_X at concentrations of 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 the duration of operation at low load. Note also that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane. Actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

The following table summarizes the results of the new and clean tests conducted on one of the dual-fuel GE PG7241FA gas turbines operating in simple cycle mode and burning natural gas at the existing Tampa Electric Polk Power Station.[3] The DLN 2.6 combustors for this project (Units 2 and 3) were guaranteed to achieve a NO_X rate of 9 ppmvd @ 15% O_2 while burning natural gas although the permit limit is 10.5 ppmvd @ 15% O_2.

Table 3A. TECO Polk Power Station Emission Test Results

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
Limit	10.5	15	7

The above test results confirm NO_X, CO, and VOC emissions less than the emission characteristics published by General Electric in Figure 3.4 above.

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in G or H Class units, which are larger units than planned for this project at the Polk Power Station. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG).

In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 3.1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN combustion 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% compared with uncontrolled emissions and a reduction greater than 90% compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[4] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical. There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[5] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[6] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[7] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines. It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for this project.

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 gas 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 gas turbines, for further reduction to BACT limits by other techniques as discussed below. During dry low-NOx combustion for gas firing, wet injection is not employed.

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, vanadium 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 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 systems 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 conventional 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 gas turbines. 3.5 ppmvd on gas.
- FPL Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FPL Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require conventional SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil. SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle gas turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing).

SCONO$_X$^{TM}. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within the heat recovery steam generator (HRSG) of a combined cycle gas turbine unit.

SCONO$_X$^{TM} systems were installed at seven sites ranging in capacity from 5 to 43 MW.[8] None were installed at large facilities. SCONO$_X$^{TM} technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx^{TM} has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx^{TM} systems also oxidize emissions of CO and VOC for additional emission reductions. SCONO$_X$^{TM} can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

Table 3B contains averaged cost values for SCONO$_X$™ and SCR developed by the California Air Resources Board for their Legislature.[9] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 3B. Cost Comparison between SCR and SCONO$_X$ for a 500 MW Combined Cycle Gas Turbine System

Capital Cost ($)		Annual O&M Cost ($)	
SCR + Oxidation Catalyst	SCONO$_X$™	SCR + Oxidation Catalyst	SCONO$_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with SCONO$_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR + oxidation catalyst package costs much less than the SCONO$_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering. While the Department does not accept or reject these figures, it appears that SCONO$_X$™ is not cost-effective for the present project.

Applicant's NOx BACT Proposal

For the proposed large simple cycle gas turbine project, the applicant evaluated the remaining available combustion and post-combustion technologies for the control of NO$_X$ emissions: DLN combustors and an SCR system. The applicant estimated the capital cost of a hot SCR system at $15,721 and the total annualized costs including operation to be $4,140,900. Assuming approximately a 70% reduction in NOx emissions, the applicant estimated that a hot SCR system could reduce NOx emissions by 383.2 tons per year. The cost effectiveness for a hot SCR system was estimated to be $10,807 per ton of NOx removed. (The analysis was based on the original proposal of 750 hours of oil firing.) The applicant concluded that a hot SCR system was not cost effective for this project. Therefore, the applicant proposed a NOx BACT standard of 10.5 ppmvd @ 15% O_2 based on dry low-NOx combustion and the exclusive firing of natural gas. The applicant later revised this request to "9.0 ppmvd @ 15% O_2".

Department's Review and Draft NOx BACT Determination

The Department recognizes a hot SCR system as the "top" available and feasible control technology for the large simple cycle gas turbine project. Although the Department does not fully endorse the applicant's SCR cost estimate, it agrees that the installation of a hot SCR system on such a project with restricted operation is not cost effective. However, it is noted that a hot SCR system begins to approach the level of cost effectiveness with the elevated number of hours of requested operation for each simple cycle gas turbine (4380 hrs per year).

The proposed gas turbines are existing units originally constructed for a project in another state. Although the gas turbines have a guaranteed NOx emissions rate of "9 ppmvd @ 15% O_2", the applicant contends that this is for "new and clean" units. The applicant's request for a NOx standard of "10.5 ppmvd @ 15% O_2" is to recognize the possibility for slight degradation of the units due to the frequent startups and shutdowns needed for simple cycle operation. In addition, the proposed NOx standard is consistent with the most recently permitted simple cycle unit at this plant.

Numerous General Electric PG7241(FA) simple cycle gas turbine have been permitted throughout Florida and the United States with NOx emissions standards of "9 ppmvd @ 15% O_2". Many of these have completed construction and are currently in operation. These units have been able to continuously demonstrate compliance with the permitted NOx emissions standards. The following table shows several such BACT determinations for other units similar to those proposed for this project.

Table 3C. Recent NO_X Standards for F-Class Simple Cycle Gas Turbine Projects

Project Location	Capacity (MW)	NO_X Limit ppmvd @ 15% O2	Technology	Comments
El Paso Manatee, FL	350	9 NG	DLN	2x175 MW GE 7FA CTs (Gas only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Enron Pompano, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Revised Draft 06/01. 500 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA GTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F GTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F GTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA GTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F GTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA GTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G GT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
GT = Gas Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Below, Figure 3.5 is a representation of hourly readings (including startup and shutdown) from the TECO Polk Unit 2 acid rain NO_X CEMS. This unit is identical to the proposed unit. It can be seen that the bulk of the readings (representing steady state operation) are below 10 ppmvd.

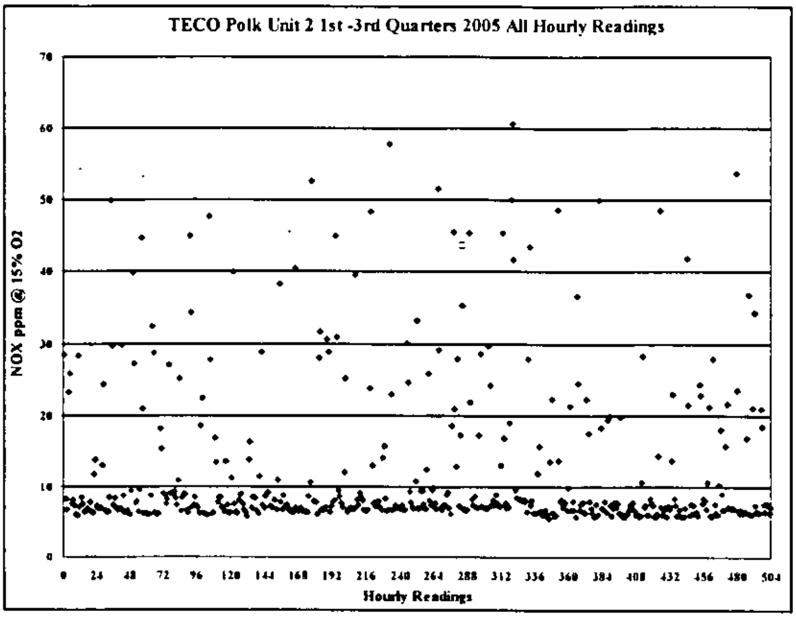

Figure 3.5 TEC Polk Unit 2 Hourly Readings

Figure 3.6 represents the same data with hourly readings attributed to startup and shutdown removed. Only two hourly readings are above 10 ppmvd and most of the readings are well below 9 ppmvd.

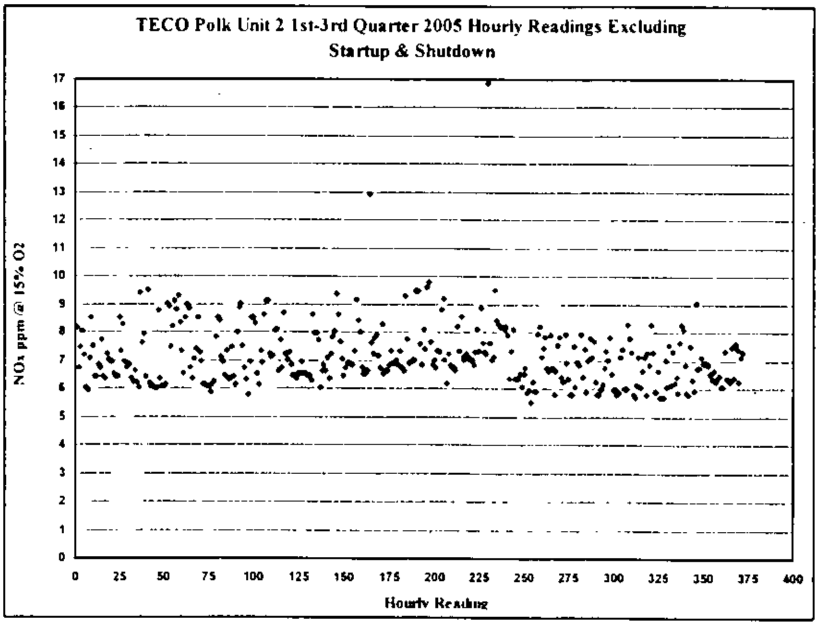

Figure 3.6 TEC Polk Unit 2 Hourly Readings Excluding

It should be noted that Polk Power Unit 2 is permitted at 10.5 ppmvd while still achieving these low NOx values. Acid Rain data can be obtained for other similar units that have been permitted at 9 ppmvd. Clearly these units are capable of operating below NOx limit guaranteed by General Electric. The Department considered recently permitted similar projects, data from existing similar units, the requested frequent operation, and the initial vendor guaranteed emissions rate. Based on this information, the Department's draft NOx BACT determination is 9.0 ppmvd @ 15% O_2 (24-hour daily average) based on dry low-NOx combustion and the exclusive firing of natural gas. The averaging time provides sufficient consideration for any "degradation" due to the frequent startups and shutdowns associated with simple cycle operation expressed as a concern by the applicant.

Initial CO BACT Review

Descriptions of CO Emissions

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and distillate oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most gas turbines incorporate efficient combustion designs featuring high temperatures and sufficient time, turbulence, and excess air to minimize CO emissions. Additional control can be obtained by installation of oxidation catalyst, particularly on gas turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are reported for large gas turbines at full load without use of oxidation catalyst. As discussed under the NO_X technology section above, the GE 7FA Unit 2 at the TECO Polk Power Station has achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at loads between 50% and 100%. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE 7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO emissions. Continuous data from these units verify the ability of the GE 7FA gas turbine to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data for four GE 7FA units at TECO's Bayside Power Station is shown in the following table.

Table 3D. CO CEMS Data – TECO Bayside Combined Cycle Unit 1

Quarter	Gas Turbine	CO Emissions in ppmvd		
		Maximum 24-hour Block	Minimum 24-hour Block	Quarterly Average
3rd Quarter 2003	1A	4.3	0.3	0.83
	1B	1.7	0	1
	1C	2.1	0	0.8
4th Quarter 2003	1A	2.2	0	0.76
	1B	1.9	0	1.14
	1C	1.2	0	0.74

CO and VOC emissions should be low because of the very high combustion temperatures, excess air, and turbulence characteristics of the GE 7FA. Performance guarantees are only now "catching up" with the field experience. In fact, General Electric recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[10] The following statement was taken from the report:

> *"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation – thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."*

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

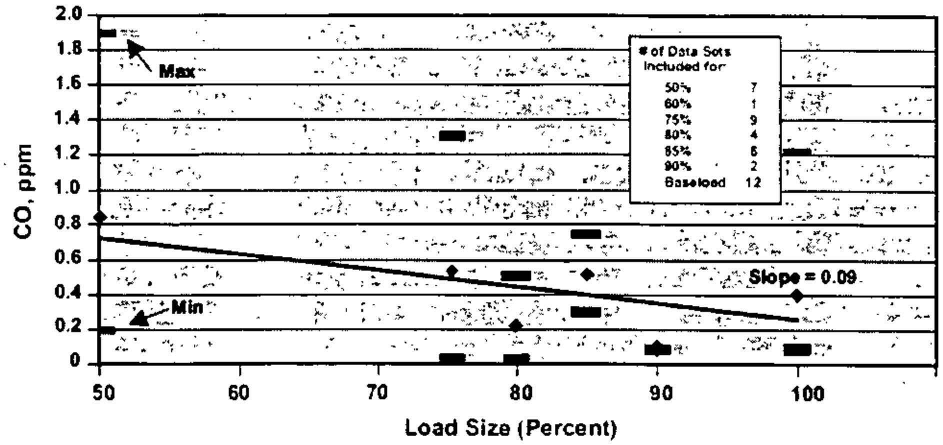

Figure 3.7 Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Applicant's CO BACT Proposal

For the proposed large simple cycle gas turbine project, the applicant evaluated an oxidation catalyst plus the dry low-NOX combustion controls as the top control option for the project. The applicant estimated the capital cost of oxidation catalyst systems for the project at \$6,263,142 and the total annualized costs to be \$1,266,415. Assuming a 90% reduction in CO emissions, the applicant estimated that an oxidation catalyst could reduce CO emissions by 204 tons per year, which results in a cost effectiveness of \$6203 per ton of CO removed. (This analysis included oil 750 hours of firing with much higher CO emissions.) The applicant concluded that an oxidation catalyst was not cost effective for this project. Therefore, the applicant proposes a CO BACT standard of 9.0 ppmvd @ 15% O_2 (24-hour average) based on the dry low-NOx combustion characteristics of the GE 7FA gas turbine and the exclusive firing of natural gas.

Department's CO Review

Table 3E summarizes several CO BACT determinations for recent projects in Florida and other states. TECO's proposal is included for comparison. Most of the projects cited required an oxidation catalyst. The "top" emission limit is considered by the Department to be 2.0 ppmvd @ 15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

Table 3E. CO Standards for "F-Class" Combined Cycle Units

Project Location	CO Standards, ppmvd @ 15% O_2
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)
Duke Morro, CA	2.0 (Ox-Cat)
ANP Blackstone, MA	3.0 (Ox-Cat)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)
FPL Turkey Pt., FL	4.1 – NG (DB off, AnnualTest) 7.6 – NG (DB on, Annual Test)

Project Location	CO Standards, ppmvd @ 15% O_2
	14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)
Polk Power Station, FL	9.0 NG (24-hr block)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)
Calpine OEC, PA	10 (1-hr)
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)
PGN Hines IV, FL	8.0 - NG 12.0 – FO
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)
Metcalf Energy, CA	6 - NG (100% load)
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

With an oxidation catalyst, a GE 7FA unit will likely achieve CO values below 2 ppmvd @ 15% O_2. Although General Electric will guarantee the GE 7FA gas turbine for 4.1 ppmvd @ 15% O_2, the data suggest actual emissions without an oxidation catalyst will be approximately equal to the "top" emission limit of 2 ppmvd @ 15% O_2. For a unit firing only natural gas that does not experience a wide range of various operating modes, it is straightforward to conclude that it would not be cost effective to install an oxidation catalyst to reduce "permitted emissions" from 5 to 2 ppmvd @ 15% O_2. This is in agreement with the conclusion in General Electric's paper cited in the discussion above. Therefore, at this time, the Department's draft CO BACT determination would be 4.1 ppmvd @ 15% O_2 (24-hour daily average) based on dry low-NOx combustion and the exclusive firing of natural gas. The averaging time provides sufficient consideration for any "degradation" due to the frequent startups and shutdowns associated with simple cycle operation expressed as a concern by the applicant.

Application Revision – CO Emissions Cap

During the processing of this application, the applicant requested a CO emissions cap of 99.0 tons per consecutive 12 months to avoid PSD preconstruction review for the project. TECO operates numerous General Electric 7FA units and has available CO CEMS emission data related to startups and shutdowns. The Department has some information related to CO emission levels during these periods. Some important items for consideration are:

- The General Electric 7FA unit can achieve full lean pre-mix combustion in less than 20 minutes and shutdown in less than 15 minutes.
- In general, both CO and NOx emissions follow steep "saw-tooth" profiles at the low loads experienced during startup. See Figure 3.8 below.

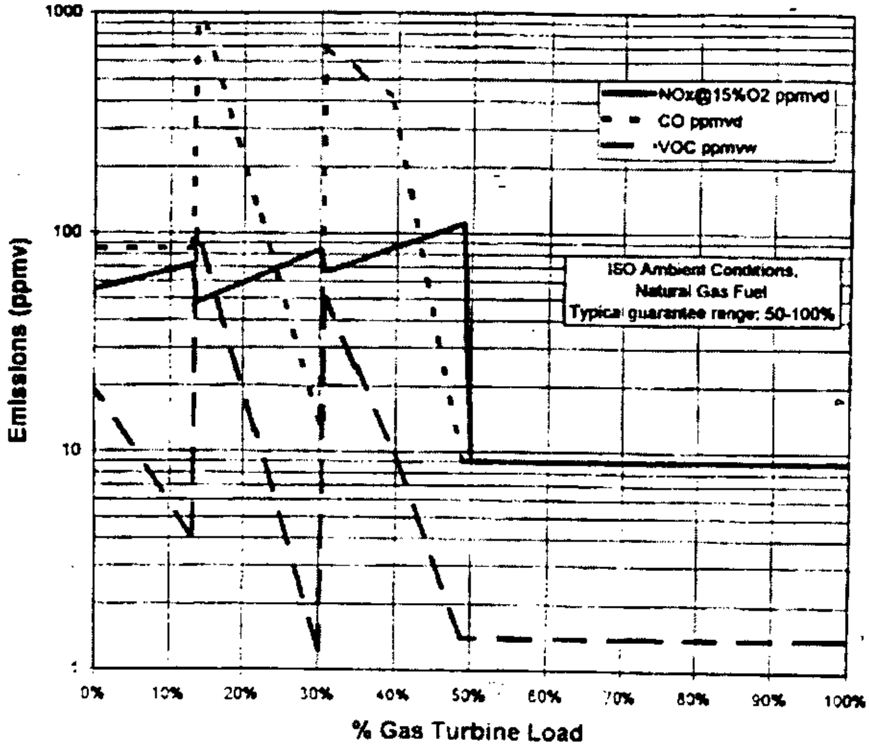

Figure 3.8 CO and NOx Emissions at Low Loads

- Operation at each of the low load, high emissions peaks is very short in duration. Low loads mean reduced fuel firing and less exhaust flow. This means that, although the pollutant concentrations may be much higher, the influence in mass emissions rate will not be as great. [11]
- Given an ambient temperature of 55° F, General Electric specification sheets from 1999 conservatively indicate CO emissions of 29 lb/hour (9 ppmvd) at 100% load, 24 lb/hour (9 ppmvd) at 75% load, 20 lb/hour (9 ppmvd) at 50% load, and 92 lb/hour (47 ppmvd) at 25 % load.
- CO emissions during normal operation (above 50% load) are typically much less than 2 ppmvd @ 15% O2, which would be approximately 7.5 lb/hour.

As a "reality check", the Department made the following assumptions and estimates.

	CO, ppmvd	CO, lb/hour	Frequency	Duration	Hours	CO, TPY
Startup	---	184 [a]	366 [b]	20 min. [c]	122	11.2
Shutdown	---	184 [a]	366 [b]	15 min. [c]	91.5	8.4
Normal	3.9 [d]	14.6 [d]	---	---	4075	29.7
Total	---		---		4380	49.3
	---		---		2 Units	98.6

Notes:

a. Assume that the CO mass emission rate during a startup or shutdown is twice that recognized by General Electric at 25% load.

b. Assume that a unit will have 366 startups and shutdowns each year.

c. Assume that a unit will average 20 minutes to startup and 15 minutes to shutdown.

d. Assume that the CO emissions rate during normal operation is nearly twice that experienced by similar units operating above 50% load.

Based on this rough estimation, it appears that the plant can manage operation of the new simple cycle units below the CO significant emissions rate of 100 tons per year to avoid PSD preconstruction review. Therefore, the draft permit will include the following emissions limits:

Emissions Cap: As determined by a certified CEMS, CO emissions from Units 4 and 5 (combined) shall not exceed 99.0 tons during any consecutive 12 months, rolling total. All valid emissions data shall be used to demonstrate compliance with the emissions cap, including startups, shutdowns, and malfunctions.

Initial Limit: CO emissions shall not exceed 9.0 ppmvd @ 15% O_2 (36.0 lb/hour) as determined by initial tests for the units as constructed.

Sulfur Dioxide (SO_2) BACT Determination

The control of sulfur dioxide (SO_2) and sulfuric acid mist (SAM) emissions can be divided into five categories: restricting fuel sulfur content; absorption by scrubbing solution; adsorption on a solid bed; direct conversion to sulfur; or direct conversion to sulfuric acid. A review of BACT determinations for gas turbines on EPA's RCAT/BACT/LAER Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the "top control" option for SO_2 and SAM emissions. Gas turbines typically fire clean, low fuel sulfur fuels to prevent fouling turbine blades causing excessive maintenance. The combination of low sulfur fuels with high exhaust flow rates makes add-on controls prohibitively costly. For the project, the applicant proposes the exclusive firing of natural gas containing no more than 2 grains per 100 scf as SO2 BACT. The Department agrees and the draft SO_2 BACT standard is the proposed fuel specification.

Particulate Matter (PM/PM_{10}) BACT Determination

Particulate matter (PM/PM_{10}) is emitted from gas turbines due to ash present in the fuels fired and incomplete fuel combustion. Particulate matter emissions are minimized by the use of clean fuels, an efficient combustion design, and good combustion practices. For the project, the applicant proposes to fire natural gas as the exclusive fuel. Natural gas is a clean fuel, contains little or no ash, and is efficiently combusted a gas turbine. Again, clean fuels are necessary for gas turbines to avoid damaging turbine blades and other components already exposed to very high temperatures and pressures. The applicant proposes a PM/PM_{10} BACT for as the efficient combustion design of the GE 7FA gas turbine and the exclusive firing of natural gas with a sulfur content of no more than 2 grains per 100 scf. In addition, visible emissions from the stack will be limited to no more than 10% opacity based on a 6-minute average. The Department agrees and the draft PM/PM_{10} BACT standard is the proposed fuel specification as well as the proposed opacity standard.

Summary of Department's Draft BACT Determinations

The Department establishes the following standards as the Best Available Control Technology (BACT) for the simple cycle gas turbine Units 4 and 5 at the TECO Polk Power Station.

Table 3F. Draft BACT Determinations – TECO Polk Power Station Simple Cycle Units 4 and 5

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA METHOD 9 TEST	BACT
	2 grains S/100 SCF of gas	N/A	RECORD KEEPING	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates 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 both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

4. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Gas Turbines – NSPS Subpart GG

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These provisions result in the following standards based on compressor inlet conditions of 59° F, full load, and 60% relative humidity.

- $NO_X \leq 109.2$ ppmvd @ 15% O_2 corrected for a heat rate of 9370 Btu/KW-h LHV at peak load;
- $SO_2 \leq 0.015\%$ by volume at 15% O_2 on a dry basis (150 ppmvd @ 15% O_2) or the use of a fuel with a sulfur content $\leq 0.8\%$ sulfur by weight (8000 ppmw).

A more recent standard, Subpart KKKK, was proposed by EPA on February 18, 2004. The proposed standard would require compliance with a NO_X standard of ≤ 0.39 lb/MW-hour. For this project, this is approximately equal to 11 ppmvd @ 15% O_2. However, the final rule will not be applicable to the Units 4 and 5 at the Polk Power Station because a purchase contract with General Electric was signed on July 21, 2000 for these units, which is prior to the NSPS effective date.

The Department considers the draft BACT standards to be more stringent than the existing or the proposed 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.

5. PERIODS OF EXCESS EMISSIONS

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 CO and NO_X emissions.

Excess Emissions Allowances

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." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

The General Electric Frame 7FA gas turbines operate with low NOx emissions in full lean pre-mix mode, which is achieved in the range of 40% to 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. Also, the units require some tuning to maintain the low emissions levels. Tuning involves stepping the gas turbine from low load operation through base load operation to collect data on existing operating levels. 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. Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine for which a limited amount of data may be excluded from the continuous compliance determinations for NO_X emissions.

Definitions: Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

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.

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.]

Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

Allowable NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, NO_X continuous monitoring data collected during periods of startup, shutdown, and malfunction may be excluded from the 24-hr block compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, and DLN tuning) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 30 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup shall be excluded.

b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 20 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 20 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

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.]

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report annual emissions for the Annual Operating Report and demonstration of compliance with the CO emissions cap. [Rules 62-4.070(3), 62-210.200, 62-212.400(BACT) and 62-210.700, F.A.C.]

6. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will result in emissions of three criteria pollutants in excess of PSD significant emission rates for NO_X, PM_{10}, SO_2. Each pollutant is a criteria pollutant with regulations defining national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels. Note: Based on the revised request, the project is no longer subject to PSD review for CO emissions.

However, CO was originally modeled and this information is provided in this summary.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant 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.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the St. Petersburg/Clearwater International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1992 through 1996. These stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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 if and when EPA revises 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.

PSD Class I Area

The closest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA), which is greater than 50 km from the proposed facility. Therefore, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analyses

A significant impact analysis was performed for PM_{10}, NO_X, SO_2, and CO emissions. For this analysis, inputs to the models are based on the potential emissions from the project at worst-case load conditions. The models used in this analysis and any required subsequent modeling analyses are described in *Models and Meteorological Data Used in the Air Quality Analysis*, later in this section. Based on the modeling analysis, the highest predicted short-term concentrations and the highest predicted annual averages are compared to the corresponding significant impact levels for the Class I and Class II Areas. If modeling at worst-case load conditions shows significant impacts, additional modeling to include emissions from nearby facilities (multi-source modeling) is required to determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, no further modeling is required.

Class II Significant Impact Analysis

For the simple cycle gas turbine project firing only natural gas, the applicant's air quality impact analyses predicts impacts from all pollutants to be much less than the regulatory "significant impact levels." The results of the modeling analysis are summarized in the following table and compared with the National Ambient Air Quality Standards.

Table 6A. Maximum Predicted Impacts Compared to the PSD Class II Significant Impact Levels and AAQS

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Significant Impact Levels (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.002	1	60	No
	24-Hour	0.03	5	260	No
	3-Hour	0.2	25	1300	No
PM_{10}	Annual	0.005	1	50	No
	24-Hour	0.08	5	150	No
NO_2	Annual	0.01	1	100	No
CO	8-hour	0.3	500	10,000	No
	1-Hour	0.8	2000	40,000	No

As shown in the table, the maximum predicted impacts from the project are much less than the respective ambient air quality standards and significant impact levels. Therefore, no further modeling is necessary.

Class I Significant Impact Analysis

The nearest PSD Class I Area is the Chassahowitzka National Wilderness Area (CNWA), which is located about 120 km to the north. The applicant's initial PM_{10}, NO_X and SO_2 air quality impact analyses for this project predicted maximum impacts from all pollutants to be less than the applicable "significant impact levels" for the Class I Area. The results of the modeling analysis are summarized in the following table.

Table 6B. Maximum Predicted Impacts Compared with PSD Class I (CNWA) Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	No
	24-hour	0.03	0.3	No
NO_2	Annual	0.004	0.1	No

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
SO_2	Annual	0.004	0.1	No
	24-hour	0.07	0.2	No
	3-hour	0.3	1	No

Note that the maximum predicted impacts from the project are miniscule when compared with the ambient air quality standards shown in the previous table. Because the predicted impacts are much less than the respective significant impact levels, no further modeling analysis is necessary for the Class I Area.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for each pollutant with a regulatory de minimis impact level. If the de minimis levels are exceeded, the Department may require pre-construction ambient monitoring. For this analysis, inputs to the models are based on the potential emissions from the project at worst-case load conditions. As shown in the following table, the maximum predicted impacts for all pollutants are less than the regulatory de minimis impact levels. Therefore, no pre-construction monitoring is required.

Table 6C. Maximum Predicted Impacts Compared to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	De Minimis Levels (ug/m^3)	Maximum Baseline Concentrations (ug/m^3)	Impacts Greater Than De Minimis?
PM_{10}	24-hour	0.08	10	~ 80	No
NO_2	Annual	0.01	14	~ 20	No
SO_2	24-hour	0.07	13	~ 45	No
CO	8-hour	0.3	575	~3000	NO

Based on the preceding discussions, no further modeling analysis is necessary. However, the PSD regulations require an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Additional Impacts Analysis

<u>Impact on Soils, Vegetation, and Wildlife</u>

Very low emissions are expected from this natural gas-fired gas 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}, NO_X, SO_2, and CO as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

The project impacts are also less than the significant impact levels for PM_{10}, NO_X,SO_2, and CO 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. The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition in the PSD Class I Area.

<u>Impact On Visibility</u>

Natural gas is a clean fuel and combustion results in very low particulate matter emissions. The very low NO_X

and SO_2 emissions will also minimize plume opacity and any effects on regional visibility. The Class I Chassahowitzka NWA, where visibility impacts are considered, is about 120 kilometers from the proposed site. A regional haze analysis using the CALPUFF model and natural gas emissions predicted impacts less than the federal land manager's visibility impairment criteria; therefore, impacts on visibility are expected to be insignificant.

Growth-Related Air Quality Impacts

According to the applicant, the project will require about 5 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal. This project is a response to statewide and regional growth and also accommodates future growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint." After construction of the proposed project, Polk County is expected to remain below the National Ambient Air Quality Standards.

Hazardous Air Pollutants

The existing Polk Power Station is not a major source of hazardous air pollutants (HAPs). Therefore, the project is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

7. 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 analyses, and the conditions specified in the draft permit. Jeff Koerner is the project review engineer and is responsible for preparing the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis.

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9 Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

10 Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.

11 Technical Report GER-4249. Stephanie Wien, Jeanne Beres, and Brahim Richani. GE Energy. "Air Emissions Terms, Definitions and General Information". August 2005

DRAFT PERMIT

PERMITTEE:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111
Authorized Representative:
Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Expires: October 1, 2008

PROJECT AND LOCATION

This permit authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix C. Common State Rules

Appendix GC. General Conditions

Appendix GG. NSPS Provisions - Subparts A and GG for Stationary Gas Turbines

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

Michael G. Cooke, Director
Division of Air Resource Management

Effective Date: ____________________

FACILITY DESCRIPTION

The regulated emissions units at the existing Polk Power Station include the following: a 260 MW integrated coal gasification and combined cycle gas turbine (Unit 1) capable of firing synthetic gas (syngas) or No. 2 fuel oil; an auxiliary boiler that fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and two nominal 165 MW simple cycle gas turbines (Units 2 and 3) capable of firing either natural gas or No. 2 fuel oil.

PROJECT DESCRIPTION

The project is for the addition of two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing facility. Each unit may operate up to 4380 hours per year. The new units will be fired exclusively with natural gas, which will minimize SO_2 emissions. The units will be designed and constructed with dry low-NO_X burner technology for the control of NO_X emissions. The advanced burner design will reduce incomplete combustion and minimize CO, PM_{10}, and VOC emissions.

EMISSIONS UNITS

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

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

REGULATORY CLASSIFICATION

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

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

Title V: The facility is a Title V or "major source" of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

NSPS: Units 4 and 5 are subject to 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). They are not be subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005) because the purchase contract with General Electric was signed on July 21, 2000, which is prior to the NSPS effective date.

NESHAP: Units 4 and 5 are not subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) because the facility is not a major source of HAPs.

Siting: This plant is subject to certain requirements of Chapter 403, Part II, Florida Statutes, Electric Power Plant and Transmission Line Siting, including a modification of the conditions Site Certification PA92-32.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; and the Department's Final Determination and Best Available Control Technology (BACT) determinations.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify emissions unit should be submitted to the Bureau of Air Regulation (BAR), 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.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Department's Southwest District Office at 13051 N. Telecom Parkway, Temple Terrace, FL 33637-0926.

3. 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.]

4. 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, 62-214, 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.]

5. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. 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.]

6. 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.]

7. Source Obligation.

   (a) 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.

(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 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.

(c) 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.]

8. 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. [Chapters 62-210 and 62-212, F.A.C.]

9. 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]

10. 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. Simple Cycle Gas Turbine Units 4 and 5 (EU-011 and EU-012)

The specific conditions of this subsection apply to the following emissions units.

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Units 4 and 5 are subject to determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The gas turbines shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart GG (Standards of Performance for Stationary Gas Turbines). See Appendix GG of this permit. The BACT emissions standards are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards. [Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60, Subparts A and GG]

EQUIPMENT DESCRIPTION

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two General Electric Model PG7241FA gas turbine-electrical generator sets with a nominal generating capacity of 165 MW each. Each gas turbine will be equipped with a DLN combustion system and an inlet air filtration system. The unit shall include a Speedtronic™ Mark VI automated gas turbine control system (or equivalent). [Application No. 1050233-018-AC; 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 gas turbines 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 CO and NO_X. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Application No. 1050233-018-AC; Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: Each gas turbine shall operate no more than 4380 hours during any consecutive 12 months. Restrictions on individual methods of operation are specified in separate conditions. [Application No. 1050233-018-AC; Rules 62-210.200(PTE) and 62-212.400(12), F.A.C.]

6. Permitted Capacity: The maximum heat input rate for each gas turbine is 1834 MMBtu per hour when firing natural gas based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas, 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. [Rules 62-4.070(3), 62-212.400(BACT), and 62-210.200(PTE), F.A.C.]

7. Authorized Fuels: Each gas turbine shall fire only natural gas containing no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

8. Simple Cycle, Intermittent Operation: Each 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 determinations 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

9. Emission Standards: Emissions from each gas turbine shall not exceed the following emissions standards.

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring systems (CEMS) for both units combined.

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates 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 both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

[Rule 62-212.400 (BACT), F.A.C.; Rule 62-4.070(3), F.A.C.]

10. 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.]

11. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental)
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources Note: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide 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 Department. Tests shall be conducted in accordance with the appropriate test method, the applicable requirements specified in Appendix C of this permit, and the provisions in NSPS Subparts A and GG in 40 CFR 60. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Subparts A and GG, and Appendix A.]

12. Testing Requirements: Initial and subsequent performance 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. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

13. Initial Compliance Demonstration: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after the initial startup. In accordance with the test methods specified in this permit, the turbine exhaust stack shall be tested to demonstrate compliance with the emission standards for CO, NO_X, and visible emissions. For each test run (including visible emissions tests), CO and NOx emissions recorded by the required CEMS shall be reported. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

14. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests for visible emissions shall be conducted. For each visible emissions test, emissions of CO and NOx recorded by the CEMS shall also be reported. [Rules 62-297.310(7)(a) and (b), F.A.C.]

15. Continuous Compliance: Continuous compliance with the CO and NOx emissions standards shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). [Rules 62-297.310(7)(a) and (b), F.A.C.]

16. 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. The Department may, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the DLN combustors, etc. [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. 9 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

17. 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 gas turbines, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

18. Definitions: Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

    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.

19. 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.]

20. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

21. Allowable NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, NO_X continuous monitoring data collected during periods of startup, shutdown, and malfunction may be excluded from the 24-hr block compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, and DLN tuning) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 30 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup shall be excluded.

    b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 20 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 20 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

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.]

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report annual emissions for the Annual Operating Report and demonstration of compliance with the CO emissions cap. [Rules 62-4.070(3), 62-210.200, 62-212.400(BACT) and 62-210.700, F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

22. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. All continuous monitoring systems shall be installed and functioning within the required performance specification by the time of the initial performance tests.

   a. *CO Monitor:* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The annual and required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

   b. *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.

   c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are 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), 62-210.800, 62-212.400(BACT) and 62-297.520, F.A.C.]

23. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the gas turbine stacks to measure and record the emissions of CO, and NO_X in a manner sufficient to demonstrate compliance with the emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall be corrected to

ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

a. *Valid Hourly Averages:* 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 (except for the allowable NOx data exclusions), shall be used to calculate a 1-hour block average that begins at the top of each hour. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour. *{Permitting Note: For example, a 20-minute startup begins at 2:50 p.m. and ends at 3:10 pm. This means that 10 minutes of startup data would be excluded from the first hourly average and 10 minutes would be excluded from the second hourly average.}*

b. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive valid hourly average concentration values. If a unit operates less than 24 hours during the block, or there are less than 24 valid hourly averages available, the 24-hour block average shall be the average of all available valid hourly average concentration values for the 24-hour block. *{Permitting Note: For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. For example, the "24-hr block average" may consist of only 6 valid operating hours for the day.}*

c. *12-Month Rolling Total*: By the end of each month, each CEMS shall determine a 12-month rolling total of CO emissions from each gas turbine and the combined total. The 12-month rolling total shall be based on all valid CO CEMS data collected, including startups, shutdowns, and malfunctions.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of NOx CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 21 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% 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 Compliance Authority.

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

Reporting and Record Keeping Requirements

24. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and DLN tuning). This shall be achieved through monitoring daily rates of

consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D, and recording the data using a monitoring component of the CEMS system required above. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. 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 gas 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 62-212.400(BACT), F.A.C.]

26. Fuel Sulfur Records: 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. These 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), 62-212.400(BACT), F.A.C.]

27. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority 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 Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix C. [Rule 62-297.310(8), F.A.C.]

28. CEMS RATA Reports: Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Excess Emissions Reporting

    a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority 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 of the following for each gas turbine: a summary of the 24-hour NOx compliance periods for the quarter; a summary of NOx data excluded due to malfunctions for the quarter; a summary of the 12-month rolling CO emissions totals for the quarter; and a summary of the CEMS systems monitor availability for the quarter.

    c. *NSPS Semi-Annual Reports*: Within thirty (30) days following each calendar semiannual period, the permittee shall submit a report including any applicable periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

    [Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C.; and 40 CFR 60.7 and 60.334]

30. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.C.]

31. Startup/Shutdown Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report summarizing the following for each gas turbine: number of startups and shutdowns in the quarter; the duration of each startup and shutdown in the quarter; and the CO and NOx mass emission rates (lb/hour) during each 1-hour block that includes a startup or shutdown. This temporary report that shall be submitted to the Compliance Authority and the Bureau of Air Regulation only for the first four initial quarters of operation. [Rule 62-4.070(3), F.A.C.]

SECTION IV. APPENDICES

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SECTION IV. APPENDIX BD

FINAL BACT DETERMINATION AND EMISSION STANDARDS

Project Description

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions.

Air Pollution Control Equipment

Each gas turbine will be equipped with a dry low-NOx combustion system capable of achieving low CO and NOx emissions with the lean, pre-mixed combustion of natural gas. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions standards. As the only authorized fuel for the project, natural gas contains little ash or sulfur, which will minimize emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Also, natural gas is readily combusted by the large frame gas turbines and will result in negligible emissions of volatile organic compounds (VOC).

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards that represent the Best Available Control Technology (BACT).

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NOx [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates 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 both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

[Rule 62-212.400 (BACT), F.A.C.; Rule 62-4.070(3), F.A.C.]

The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original project. The final BACT determinations also consider comments received during public notice period as summarized in the Final Determination issued concurrently with the Final Permit.

COMMON STATE RULES

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the 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. This regulation does not impose a specific testing requirement. [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.]

GENERAL COMPLIANCE TESTING REQUIREMENTS

The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air. [Rule 62-297.310, F.A.C.]

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. 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. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [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. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]

    a. *Required Sampling Time.*

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

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

            (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

            (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

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

    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule 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.

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

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

14. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

    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.

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. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

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

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

   c. *Sampling Ports.*

      (1) All sampling ports shall have a minimum inside diameter of 3 inches.

      (2) The ports shall be capable of being sealed when not in use.

      (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

      (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

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

   d. *Work Platforms.*

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

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

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

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

   e. *Access to Work Platform.*

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

      (2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

   f. *Electrical Power.*

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

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

g. *Sampling Equipment Support.*

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

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

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

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

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

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

16. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

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

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

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

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

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

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

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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

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

RECORDS AND REPORTS

17. <u>Test Reports [Rule 62-297.310(8), F.A.C.]</u>

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

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

RECORDS AND REPORTS

18. <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.]

19. <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.C.]

SECTION IV. APPENDIX GC

CONSTRUCTION PERMIT 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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.
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:
        a. The date, exact place, and time of sampling or measurements;
        b. The person responsible for performing the sampling or measurements;
        c. The dates analyses were performed;
        d. The person responsible for performing the analyses;
        e. The analytical techniques or methods used; and
        f. 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.

SECTION IV. APPENDIX GG

NSPS SUBPART GG – REQUIREMENTS FOR GAS TURBINES

Simple cycle gas turbine Units 4 and 5 (Emissions Units 011 and 012) are subject to the following applicable federal New Source Performance Standards (NSPS) in 40 CFR 60.

SUBPART A - GENERAL PROVISIONS

40 CFR 60.7, Notification and Record Keeping

40 CFR 60.8, Performance Tests

40 CFR 60.11, Compliance with Standards and Maintenance Requirements

40 CFR 60.12, Circumvention

40 CFR 60.13, Monitoring Requirements

40 CFR 60.19 General Notification and Reporting Requirements

SUBPART GG – STATIONARY GAS TURBINES

60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) (b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

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

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(k) Fire-fighting turbine means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) Turbines employed in oil/gas production or oil/gas transportation means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A Metropolitan Statistical Area or MSA as defined by the Department of Commerce.

(n) Offshore platform gas turbines means any stationary gas turbine located on a platform in an ocean.

(o) Garrison facility means any permanent military installation.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) Emergency fuel is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) 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.

(t) Excess emissions means a specified averaging period over which either:

  (1) The NOX emissions are higher than the applicable emission limit in §60.332;

  (2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; 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.

(u) 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. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 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, coal-derived 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.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas 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.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) 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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 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.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NOX allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NOX emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NOX percent by volume)
N [le] 0.015	0
0.015 < N[le] 0.1	0.04(N)
0.1 < N [le] 0.25	0.004+0.0067(N-0.1)
N > 0.25	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NOX emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOX emissions shall 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.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOX emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOX and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NOX concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NOX and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NOX) and a percent O2 basis for oxygen; or

(ii) On a ppm at 15 percent O2 basis; or

(iii) On a ppm basis (for NOX) and a percent CO2 basis (for a CO2 monitor that uses the procedures in Method 20 to correct the NOX data to 15 percent O2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each 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 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 to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NOX and diluent, the data acquisition and handling system must calculate and record the hourly NOX emissions in the units of the applicable NOX emission standard under §60.332(a), i.e., percent NOX by volume, dry basis, corrected to 15 percent O2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the owner or operator has installed a NOX CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NOX emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NOX emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NOX emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NOX emissions may elect to use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NOX formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NOX) combustion mode.

(3) For any turbine that uses SCR to reduce NOX emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

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

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator 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. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NOX emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) 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 (i)(3)(i) and (i)(3)(ii) 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 §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) 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 (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), 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 between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) 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 sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) 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 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

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

(A) An excess emission shall be any unit operating hour for which the 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 §60.332, 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 shall also be considered an excess emission.

(B) A period of monitor downtime shall be 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.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) 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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NOX and diluent CEMS:

(A) (A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOX concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NOX concentration" is the arithmetic average of the average NOX concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NOX concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOX concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(A) An excess emission shall be 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.

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

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) 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 gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall 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 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned. the owner or operator may resume using the as-delivered sampling option.

(iii) 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 shall include only unit operating hours. and ends on the date and hour of the next valid sample.

(3) Ice fog. Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period. the date and time the air pollution control system was deactivated. and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) Emergency fuel. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period. the type, reasons. and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[44 FR 52798, Sept. 10. 1979. as amended at 47 FR 3770. Jan. 27. 1982: 65 FR 61759. Oct. 17. 2000; 69 FR 41360. July 8, 2004]

60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8. using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference. see §60.17). or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part. to determine NOX and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole 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.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

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

(A) [Reserved]

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

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

(A) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 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 3 points shall be located along the measurement line that exhibited the highest average normalized NOX concentration during the stratification test; or

(B) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NOXo) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

NOX=(NOXo)(Pr/Po)0.5 e19 (Ho−0.00633) (288°K/Ta)1.53

Where:

NOX = emission concentration of NOX at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,

NOXo = mean observed NOX concentration, ppm by volume, dry basis, at 15 percent O2,

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

Po = observed combustor inlet absolute pressure at test, mm Hg,

Ho = observed humidity of ambient air, g H2O/g air,

e = transcendental constant, 2.718, and

Ta = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NOX emissions after the duct burner rather than directly after the turbine. If the owner or

operator elects to use this alternative sampling location, the applicable NOX emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NOX with no additional post-combustion NOX control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NOX emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NOX CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NOX emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall 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 §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004]

P.E. CERTIFICATION STATEMENT

APPLICANT

Tampa Electric Company PO Box 111 Tampa, Florida 33601-0111	Permit No. PSD-FL-363 Project No. 1050233-018-AC TECO Polk Power Station Simple Cycle Units 4 and 5 Polk County, Florida

PROJECT DESCRIPTION

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing power plant. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions. The Department made the following draft determinations of the Best Available Control Technology (BACT).

- NOx $\leq$ 9.0 ppmvd @ 15% O_2 (24-hour daily CEMS average) based on the efficient dry low-NOx combustion design of the General Electric gas turbines and the exclusive firing of natural gas;
- PM/PM_{10} emissions will be minimized by the efficient combustion design and the exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas; and
- SO_2 emissions will be minimized exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas.

In addition, annual CO emissions from both gas turbines combined will be restricted to 99.0 tons during any consecutive 12 months rolling total. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions limits.

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

Jeffery J. Koerner 3-6-06

Jeffery F. Koerner, P.E.
Registration No. 49441

(Date)

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