

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

THRU: J. K. Pennington *JKP*

FROM: M. P. Halpin *MH*

DATE: January 7, 2005

SUBJECT: Progress Energy Florida – Hines Energy Complex
530-Megawatt Combined Cycle Project
DEP File No. 1050234-010-AC

Progress Energy has submitted a permit application, requesting permission to add another 530 megawatts of combined cycle power to the existing Hines Energy complex. Unlike the prior three power blocks, Progress has elected to install General Electric F-frame combustion turbines for this expansion. Based upon the submittals, it is apparent that some of the emissions are lower than the Siemens Westinghouse F-frame combustion turbines and this is reflected within the BACT and draft permit.

The attached draft documents reflect a proposed NO_x limit of 2.5 ppmvd and a proposed CO limit of 8 ppmvd, both while firing natural gas and measured by CEMS. The applicant has requested permission to fire 0.05% sulfur fuel oil for up to 1000 hours per year, which is higher in sulfur content than the Department's most recent fuel oil permitting actions. However, given that this is the expansion of an existing facility which currently stores and fires 0.05% sulfur oil, the draft BACT permits this fuel use.

Attached is the public notice package for the subject project. I recommend your approval.

JKP/mph

Attachments



Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

January 18, 2005

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida – Hines Energy Complex
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Re: Draft Air Permit No. PSD-FL-342
Project No. 1050234-010-AC
Hines Energy Complex, Power Block 4
Generating Capacity Increase

Dear Mr. Zirkle:

On August 6, 2004, Progress Energy Florida submitted an application to add a nominal 530 MW of generating capacity to the existing Hines Energy Complex, which is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary BACT 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 BACT 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, as well as the Department's proposed BACT Determination. 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.

As this project is subject to the power plant site certification requirements, a final permit cannot be issued until after the required hearing on this project. If you have any questions, please contact the Project Engineer, Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TV/jp/mh

"More Protection, Less Process"

Printed on recycled paper.

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

*In the Matter of an
Application for Air Permit by:*

Progress Energy Florida
Hines Energy Complex
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733

Authorized Representative:

Mr. Roger Zirkle, Plant Manager

Draft Air Permit No. PSD-FL-342
Project No. 1050234-010-AC
Hines Energy Complex
Power Block 4
Polk County, Florida

Facility Location: Progress Energy Florida operates an existing power plant located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade.

Project: The applicant proposes to install two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, a single 190 MW steam turbine-electrical generator, a small auxiliary boiler and other miscellaneous support equipment. Upon completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW. Therefore, the project subjects the facility to the power plant site certification requirements of the Department. 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 BACT 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. A copy of the project file is available at the Air Resource Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Phone: 813/744-6100).

Notice of Intent to Issue 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 comment 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, and all email or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

Permitting Authority at the above address, email or facsimile. 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 written comments or comments received at a public meeting 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. 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. If there are none, the petition must so state; (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. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.



Trina Vielhauer, Chief
Bureau of Air Regulation

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

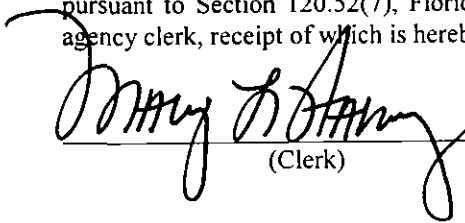
CERTIFICATE OF SERVICE

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 BACT Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/18/05 to the persons listed below.

- Mr. Jamie Hunter, Progress Energy *
- Mr. Scott Osbourn, Golder
- Mr. Jim Little, EPA Region 4
- Mr. Buck Oven, DEP-Siting
- Mr. Jerry Kissel, DEP-SWD
- 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.



(Clerk)

1/18/05

(Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1050234-010-AC (PA 92-33) / Draft Air Permit No. PSD-FL-342
Hines Energy Complex – Power Block 4
Polk County, Florida

Applicant: The applicant for this project is Progress Energy Florida. The applicant's authorized representative is Mr. Roger Zirkle, the Plant Manager of the Hines Energy Complex. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, Florida 33733.

Facility Location: Progress Energy Florida operates the existing Hines Energy Complex located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade.

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks 1 and 2) and another electrical generating unit currently under construction (Power Block 3). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2 is similar in design; the existing facility (inclusive of both Power Blocks) has a total generating capacity of 1,030 MW. Power Block 3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW.

The existing power plant is located in Polk County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, new projects at the existing facility must be reviewed for PSD applicability.

In August of 2004, the Department received a PSD permit application for the existing facility that would increase the generating output of the facility from 1560 to 2090 megawatts of output. Based on potential emissions increases, the project is subject to PSD preconstruction review for carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, and sulfuric acid mist. The Department has made a preliminary determination of the Best Available Control Technology (BACT) for each of these pollutants based on the following air pollution control equipment: low-NOx burners and a selective catalytic reduction system to reduce nitrogen oxides emissions; and the efficient combustion of clean, low-sulfur fuels to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist and sulfur dioxide. Based on the supporting air quality analysis of the potential impacts from increased operation, the applicant provided the Department with reasonable assurance that the project would not significantly contribute to or cause a violation of any state or federal ambient air quality standards and would not significantly contribute to or cause a violation of any PSD Class I or Class II increments. However, the project does require a PSD permit to authorize the requested construction, and upon completion of the project the plant will have an increase in steam-generated electrical capacity of approximately 190 MW. Therefore, the project is subject to the power plant site certification requirements of the Department.

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 and fax number is 850/921-9533.

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(Public Notice to be Published in the Newspaper)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

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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. 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. If there are none, the petition must so state; (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 Public 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. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue Air Permit is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3), F.S.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

DRAFT

PERMITTEE:

Progress Energy Florida
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Authorized Representative:

Roger Zirkle, Plant Manager – Hines Energy Complex

Hines Energy Complex, Power Block 4
Project No. 1050234-010-AC
Air Permit No. PSD-FL-342
Power Plant Siting Case No. PA 92-33
SIC No. 4911
Expires: June 30, 2009

PROJECT AND LOCATION

This permit authorizes the construction of Power Block 4 at the existing Hines Energy Complex, a “2-on-1” combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The project was processed in accordance with Florida’s 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.

CONTENTS

- Section I. General Information
- Section II. Administrative Requirements
- Section III. Combustion Turbine Specific Conditions
- Section IV. Auxiliary Boiler Specific Conditions

Michael Cooke, Director
Division of Air Resource Management

(Date)

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks 1 and 2) and another electrical generating unit currently under construction (Power Block 3). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2 is similar in design; the existing facility (inclusive of both Power Blocks) has a total generating capacity of 1,030 MW. Power Block 3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 4), the plant will have a total generating capacity of approximately 2,090 MW.

NEW EMISSIONS UNITS

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

ID	Emission Unit Description
018	Power Block 4, CT 4A (170 MW gas turbine with unfired HRSG)
019	Power Block 4, CT 4B (170 MW gas turbine with unfired HRSG)
020	Natural Gas-fired auxiliary boiler

{Permitting Note: The Hines Energy Complex, Power Block 4 (Power Block 4, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 4A and CT 4B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY. (See Appendix YYYY.)

Title IV: The facility operates emissions units subject to the acid rain provisions of the Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million British thermal units (MMBtu) per hour of heat input," which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP, or "the

SECTION I. GENERAL INFORMATION

Department”) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department’s Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix TEBD	Final BACT Determinations and Emissions Standards
Appendix GC	General Conditions
Appendix GG	NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	Semiannual NSPS Excess Emissions Report
Appendix YYYY	NESHAP Subpart YYYY

REVIEWING AND PROCESSING SCHEDULE

- Received Site Certification and PSD application on August 6, 2004;
- Additional information requested on August 19, 2004;
- Received request for additional time to respond on November 8, 2004;
- Received revised application and responses on December 6, 2004;
- Intent to Issue PSD Permit distributed January 18, 2005.

RELEVANT DOCUMENTS

The documents listed below are not attached; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application
- Department’s request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant’s additional information
- Department’s Intent to Issue

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.; and 40 CFR Parts 60, 72, 73, and 75, 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 F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
3. Construction and Expiration: 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 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(6)(b), F.A.C.]
4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
5. 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.]
6. 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]
7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. 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 with a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
POWER BLOCK 4 COMBUSTION TURBINES (EU 018 AND 019)

This section of the permit addresses the following emissions units.

Emission Units 018 and 019

Description: Emission units 018 and 019 each consist of a General Electric Model 7FA gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM₁₀, SAM, SO₂ and VOC. Dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NO_x emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Stack Parameters: Each HRSG has a stack that is 125 feet tall and 18 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,021 British thermal units (Btu) per standard cubic feet of natural gas and 19,075 Btu/lb of fuel oil.

Fuel	Heat Input Rate (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Gas	1,806 MMBtu/hour	59 °F	202 °F	67.9 ft/sec	1,036,271 acfm
Oil	1,962 MMBtu/hour	59 °F	295 °F	80.0 ft/sec	1,220,938 acfm

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

- BACT Determinations:** Determinations of BACT were made for CO, NO_x, PM/PM₁₀, sulfuric acid mist (SAM) and SO₂. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
- New Source Performance Standards (NSPS):** The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]
- National Emission Standards for Hazardous Air Pollutants (NESHAP):** The Department determines that compliance with the stationary combustion turbine requirements of 40 CFR 63, Subpart YYYYY (currently stayed) is required. See Appendix YYYYY of this permit.

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
POWER BLOCK 4 COMBUSTION TURBINES (EU 018 AND 019)

EQUIPMENT

4. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two General Electric Model 7FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]
5. Gas Turbine NOx Controls
 - a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.
 - c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

[Design; Rule 62-212.400(BACT), F.A.C.]
6. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 4A or CT 4B) and deliver steam to the steam turbine, electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]
7. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 2.5 ppmvd corrected to 15% oxygen when natural gas is fired and 5.0 ppmvd corrected to 15% oxygen when distillate oil is fired. [Rule 62-4.070(3), F.A.C.]

PERFORMANCE RESTRICTIONS

8. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, 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

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
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compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

9. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.
- a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).
 - b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 30,700,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 1,000 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*
 - c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
 - d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

10. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO ^a	8.0	12.0	24 hour block
NOx ^b	2.5	10.0	24 hour block
VOC ^c	1.3	3.0	3 hours
Ammonia ^d	5.0	5.0 ^e	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM ₁₀ ^e	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO ₂ ^f	Fuel specifications.

- a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be*

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
POWER BLOCK 4 COMBUSTION TURBINES (EU 018 AND 019)

based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to Condition No. 7 of this section.

- b. Compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO₂. Compliance with the 24-hour NO_x CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*
- c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane. *Compliance with this standard is adequate to avoid a PSD/BACT Review.*
- d. Each SCR system shall be designed and operated with an ammonia slip of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.
- e. The fuel specifications established in Condition No. 9 of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM₁₀ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.
- f. The fuel sulfur specifications in Condition No. 9 of this section effectively limit the potential emissions of SAM and SO₂ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 26 of this section.
- g. Although the ammonia slip limit is established at 5.0 ppm, compliance shall be demonstrated while combusting natural gas.

{Permitting Note: Informational only - the concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 32.1 lb/hr for natural gas firing and 57.2 lb/hr for distillate fuel oil firing,*
- *NO_x = 17.7 lb/hr for natural gas firing and 82.4 lb/hr for distillate fuel oil firing,*
- *VOC = 3.1 lb/hr for natural gas firing and 8.1 lb/hr for distillate fuel oil firing,*
- *PM₁₀ = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*
- *SO₂ = 5.4 lb/hour for natural gas firing and 109.2 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO₂ emissions. [Rule 62-212.400(BACT), F.A.C.]

STARTUP, SHUTDOWN, AND MALFUNCTION EMISSIONS

11. Operating Procedures: The 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 maintain the gas turbines, HRSGs, and pollution control systems in accordance with the

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
POWER BLOCK 4 COMBUSTION TURBINES (EU 018 AND 019)

guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

12. 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.]
13. 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.]
14. Alternate CO and NOx Emissions Standard: During any period containing 24 hours of continuous operation, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply on a 24 hour average basis:
 - a) An alternative NOx limit of 125 lb/hr shall apply if natural gas is the exclusively fired fuel;
 - b) An alternative NOx limit of 370 lb/hr shall apply if any fuel oil is fired; and
 - c) An alternative CO limit of 175 lb/hr shall apply when firing either natural gas or fuel oil.
15. Allowed Excess Emissions: Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction. Excess emissions shall in no case exceed two hours in any 24-hour period.

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

16. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of oil-to-gas fuel switches and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 10 of this section.
 - a. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.
 - b. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A “documented malfunction” means a malfunction that meets the notification requirements specified in Condition No. 27 of this section.
 - c. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

17. CEMS Data Exclusion – DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer’s specifications. A “major tuning session” would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice 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.]

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EMISSIONS PERFORMANCE TESTING

18. **Test Methods:** Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or EPA Method 320	<i>Procedure for Collection and Analysis of Ammonia in Stationary Sources</i> This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	<i>Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)</i>
9	<i>Visual Determination of the Opacity of Emissions from Stationary Sources</i> The test shall be conducted for a minimum of 30 minutes.
10	<i>Determination of Carbon Monoxide Emissions from Stationary Sources</i> This method shall be based on a continuous sampling train.
18	<i>Measurement of Gaseous Organic Compound Emissions by Gas Chromatography</i> (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	<i>Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines</i>
25A	<i>Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer</i>

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at <http://www.epa.gov/ttn/emc/ctm.html>. The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

19. **Initial Compliance Determinations:** Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Each unit shall be tested when firing natural gas and when firing distillate fuel oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. 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 SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C. and 40 CFR 60.8]
20. **Continuous Compliance:** The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM10 and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]
21. **Annual Compliance Tests:** During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

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- a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*
- b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

22. **CEMS:** The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. 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. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
 - a. *CO Monitors.* Except as otherwise specified by this condition, the 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, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and 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. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.
 - b. *NOx Monitors.* Except as otherwise specified by this condition, the NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.
 - c. *Diluent Monitors.* The oxygen or carbon dioxide (CO₂) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO₂ 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.
 - d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine

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the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO₂ on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

- e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value 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, an hourly value 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, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.
- f. *24-hour Block Averages:* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_x emissions depending on the use of alternate fuels}.* [Rule 62-212.400(BACT), F.A.C.]
- g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 17 of this section.
- h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability⁷ 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 Department's Compliance Authority.

{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

The water injection monitoring is no longer necessary due to the NSPS, Subpart GG revisions.

23. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by

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comparing NO_x emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_x monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

24. Monitoring of Operation: To demonstrate compliance with the fuel consumption limits of Condition No. 9 of this section, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]
25. Frequency of Recordkeeping: Condition No. 22 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]
26. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.
 - a. 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, D3246-81 or more recent versions.
 - b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

27. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition No. 16 of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]
28. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and

SECTION III. EMISSIONS UNIT SPECIFIC CONDITIONS
POWER BLOCK 4 COMBUSTION TURBINES (EU 018 AND 019)

fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

29. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 16 and 17 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

SECTION IV. EMISSIONS UNIT SPECIFIC CONDITIONS

POWER BLOCK 4 AUXILIARY BOILER (EU 020)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
020	Gas-fired, auxiliary boiler rated at 20 MMBtu per hour capacity

EQUIPMENT SPECIFICATIONS

1. Auxiliary Boiler: The permittee is authorized to install one auxiliary boiler designed to produce adequate steam for the cold startup of the combustion turbines. The boiler shall be designed for a nominal heat input rate of 20 MMBtu per hour from the firing of natural gas. The boiler shall fire natural gas as the exclusive fuel and this shall be considered as BACT for the emissions of particulate matter and sulfur dioxide. [Applicant Request; Design; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

2. Restricted Operation: The hours of operation of the auxiliary boiler are limited to 500 hours per year. [62-210.200(PTE), F.A.C.]

FEDERAL NSPS SUBPART DC STANDARDS

{Permitting Note: Subpart Dc regulates emissions of particulate matter and sulfur dioxide from each steam generating unit with a maximum design heat input rate of 10 MMBtu per hour or more, but less than 100 MMBtu per hour. Subpart Dc defines a steam generating unit as, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." However, Subpart Dc does not specify any emissions standards for units that combust only natural gas. Therefore, the auxiliary boiler is subject only to the following NSPS Subpart Dc requirements for notification and record keeping.}

3. Reporting and Recordkeeping Requirements of 40 CFR 60.48c: *{Original numbering is retained.}*

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

- (1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
- (3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.
- (4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

STATE STANDARDS

4. Visible Emissions – 20 percent opacity except for either one six-minute period per hour during which opacity shall not exceed 27 percent. [62-296.406 (PTE), F.A.C.]

**TECHNICAL EVALUATION
AND
PRELIMINARY BACT DETERMINATION**

Progress Energy Florida
Hines Power Block 4

530-Megawatt Combined Cycle Power Project

Polk County

DEP File No. 1050234-010-AC / PSD-FL-342 (PA 92-33)



Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
North Permitting Section

January 7, 2005

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Progress Energy Florida
 P.O. Box 14042, MAC BB1A
 St. Petersburg, Florida 33733
 Authorized Representative:
 Roger Zirkle, Plant Manager

1.2 Processing Schedule

- Received Site Certification and PSD application on August 6, 2004;
- Additional information requested on August 19, 2004;
- Received request for additional time to respond on November 8, 2004;
- Received revised application and responses on December 6, 2004.

1.3 Facility Description and Location

Power Block 1 consists of two combined cycle combustion turbines with heat recovery steam generators (HRSGs), for a nominal total of 500 MWs, a 99 MMBtu/hr auxiliary boiler, a 1,300 kW diesel generator and a 97,570 barrel fuel oil storage tank. Emissions from each CT and HRSG combination are vented through a single stack for each. Power Block 2 consists of two combined cycle combustion turbines with unfired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator. The existing facility (inclusive of both Power Blocks) has a total generating capacity of 1030 MW. Power Block 3 is under construction at the existing Hines Energy Complex. It is a “2-on-1” combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator.

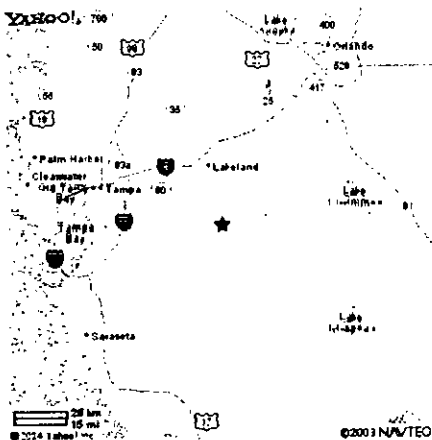


FIGURE 1 – Facility Location



FIGURE 2 – Satellite Image



FIGURE 3 – 1999 Close-up

The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10").

1.4 Regulatory Categories

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYYY, which is currently stayed.

Title IV: The facility operates emissions units subject to the acid rain provisions of the Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment" or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million British thermal units (MMBtu) per hour of heat input," which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

2. PROPOSED PROJECT

2.1 Project Description

The applicant proposes to construct a "2-on-1" combined cycle unit consisting of the following equipment and specifications: two 170 MW combustion turbine-electrical generator sets; two un-fired heat recovery steam generators; two exhaust stacks between 125 feet in height; a common steam-electrical generator (190 nominal MW); a 20 MMBtu auxiliary boiler; and other associated support equipment.

Combustion Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric 7FA gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system and an un-fired heat recovery steam generator (HRSG). Following are additional project characteristics.

- Fuels: Each gas turbine will fire natural gas as the primary fuel (0.05% Sulfur) and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 1000 hours per year per gas turbine (or equivalent) for oil firing.
- Generating Capacity: Each of the two gas turbines has a nominal generating capacity of 170 MW for gas firing. Each of the two heat recovery steam generators (HRSGs) provides

TECHNICAL EVALUATION AND PRELIMINARY BACT DETERMINATION

steam to the single steam turbine electrical generator, which has a nominal capacity of 190 MW. The total nominal generating capacity of the "2-on-1" combined cycle unit is 530 MW.

- **Controls:** CO, PM/PM₁₀, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO₂ will be minimized by firing natural gas and restricting the amounts of low sulfur distillate oil. NO_x emissions will be reduced with dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_x controls, a selective catalytic reduction (SCR) system further reduces NO_x emissions during combined cycle operation.
- **Continuous Monitors:** Each gas turbine is required to continuously monitor NO_x emissions in accordance with the acid rain provisions. CO monitors are also proposed by the applicant. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- **Stack Parameters:** Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at 125 feet tall with a nominal diameter of 18 feet. The following summarizes the exhaust characteristics:

<u>Fuel</u>	<u>Heat Input Rate (LHV)</u>	<u>Compressor Inlet Temp.</u>	<u>Exhaust Temp., °F</u>	<u>Flow Rate ACFM</u>
Gas	1806 MMBtu/hour	59° F	202° F	1,036,271
Oil	1962 MMBtu/hour	59° F	295° F	1,220,938

2.2 Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressors of the GE 7FA combustion turbines proposed for this project. The air is compressed by a pressure ratio of about 15 times atmospheric pressure. A portion of 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.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the turbine section at temperatures of approximately 2600 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1100 °F and high excess oxygen and is available for additional energy recovery.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator (HRSG). The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Figure 4 is a simplified diagram of combined cycle operation.

How a Combined Cycle Plant works

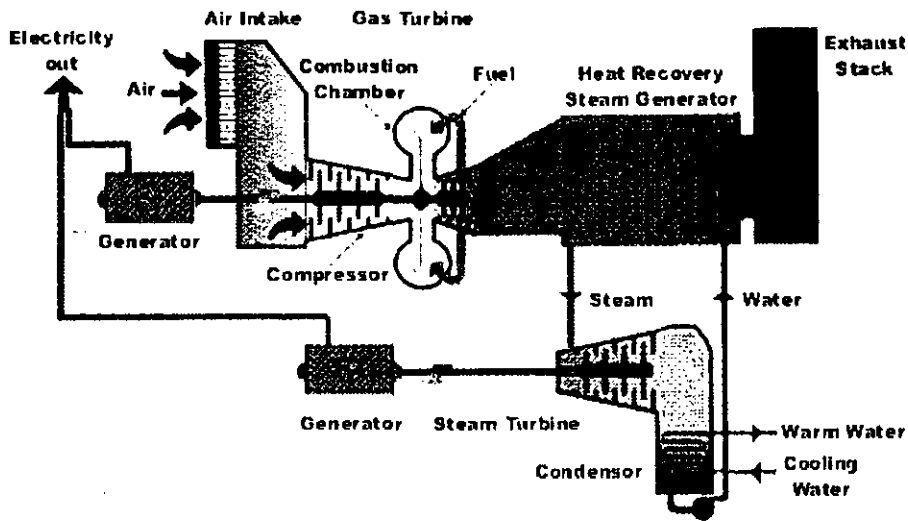


Figure 4. Key Components of a Combined Cycle Unit

2.3 Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_x), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	297	100	Yes
Pb	0.026	0.6	No
NO _x	205	40	Yes
PM/PM ₁₀	116	15/25	Yes
SO ₂	142	40	Yes
SAM	21.7	7	Yes
VOC	30.1	40	No

3. RULE APPLICABILITY

3.1 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 Florida

Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

3.2 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 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
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.

3.3 Description of PSD Applicability Requirements

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

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this

project are required for NO_x, CO, SO₂, SAM and PM/PM₁₀.

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

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - 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 energy, environmental and economic impacts, and other costs, 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.

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

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

- 3. A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

- 1. Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
- 2. All scientific, engineering, and technical material and other information available to the Department.*
- 3. The emission limiting standards or BACT determinations of any other state.*

4. *The social and economic impact of the application of such technology.*

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

4.2 NO_x BACT Determination

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_x forms in the high temperature area of the gas turbine 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.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_x formation. 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.

In all but the most recent gas turbine 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. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_x formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles.

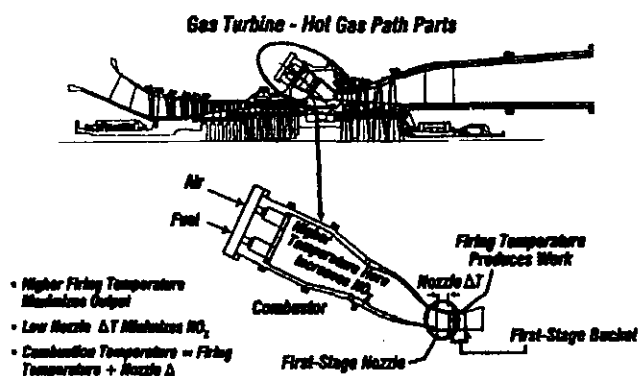


Figure 5 – Relation between Flame Temperature and Firing Temperature

Fuel NO_x is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this Progress Energy project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O₂). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O₂ for each turbine of the Progress project. The proposed NO_x controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_x emissions from large utility gas turbines such as the GE7FA is approximately 105 ppmvd @15%O₂. This constitutes the legal floor (absolute maximum NO_x value) in a "Top/Down" BACT determination.

Descriptions of Available NO_x Controls

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically 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 85% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below. 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.

Combustion Controls: Dry Low NO_x (DLN)

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. The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 6.

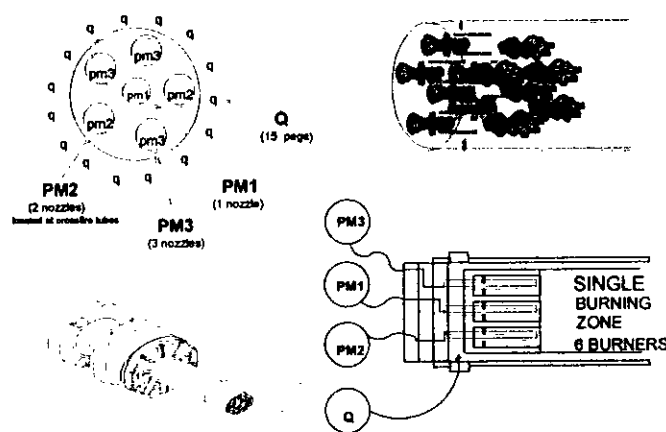


Figure 6 – DLN-2.6 Fuel Nozzle Arrangement

TECHNICAL EVALUATION AND PRELIMINARY BACT DETERMINATION

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 emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 6 for a unit tuned to meet a 15 ppmvd NO_x limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_x. Actual emissions of CO and VOC are actually much less than suggested by the diagram. However the diagram also suggests the need to minimize operation at low load conditions.

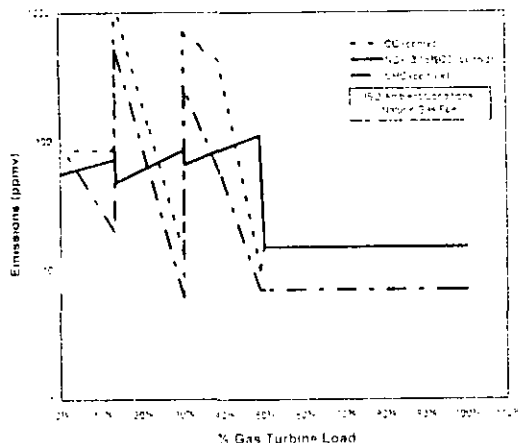


Figure 7 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_x)

The combustor emits NO_x at concentrations of 15 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. Note that VOC comprises a very small amount of the “unburned hydrocarbons” which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.

Table 2. Test Results for GE 7FA Gas Turbine, TECO Polk Power (Simple Cycle)

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

Following are the results for testing of the GE7FA combined cycle unit at the City of Tallahassee Purdom Plant.

Table 3. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station

Percent of Full Load	NO _x , ppmvd @15% O ₂	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

The test results at the TECO and Tallahassee projects confirm NO_x, CO, and VOC emissions substantially less than typical guarantees as discussed below.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_x by combustion technology. This limitation is seen in Figure 7 from an EPRI report. Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 7.

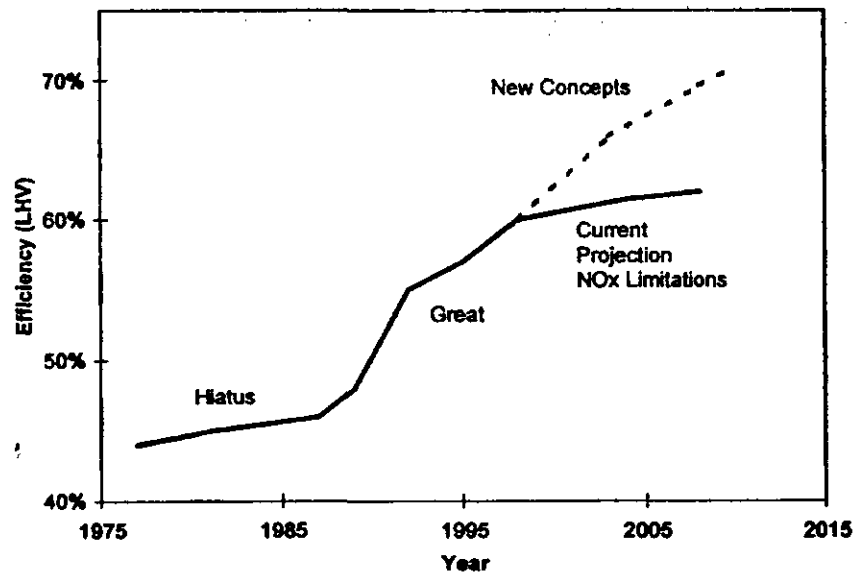


Figure 8 – Efficiency Increases in Combustion Turbines

Further NO_x reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Progress. 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 1). At the same time, thermal

efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_x control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater than 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_x emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production). Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_x emissions when firing fuel oil as discussed above.

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. 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 known 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™. 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. By now, 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. 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 the Progress Energy Hines Power Block 4 project.

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. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available and being applied in Florida. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR 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.

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project complies with a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued to Competitive Power Ventures (CPV), Calpine, Progress Energy, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O₂ by SCR. Similarly permits were issued in 2003 to FPL for projects in Manatee and Martin County each with a limit of 2.5 ppmvd @15%O₂ by SCR.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 9 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible.

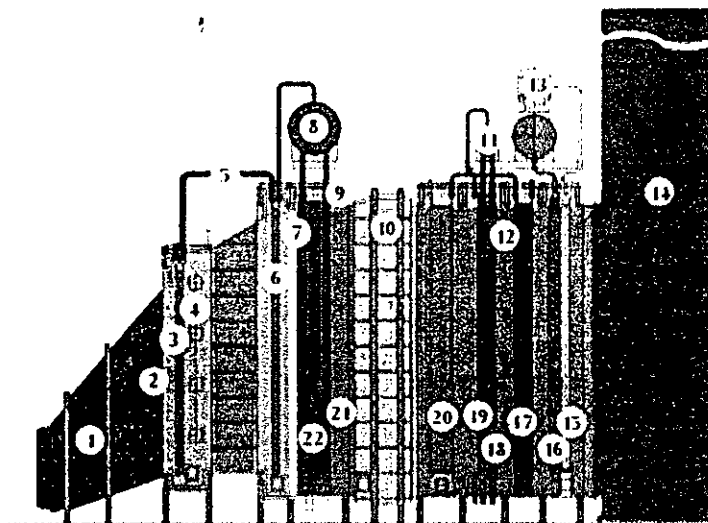


Figure 9 – Key HRSG Components (10 is SCR)

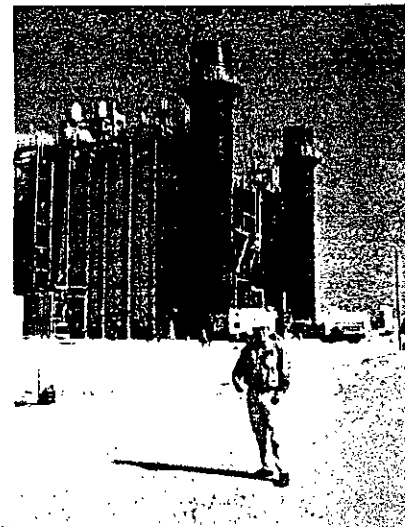


Figure 10 – Hines Power Block 1

TECHNICAL EVALUATION AND PRELIMINARY BACT DETERMINATION

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or even low sulfur fuel oil, whether distillate or residual. However, ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_x emissions less than 2.0 ppmvd @15% O₂ (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR. The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 4. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA

% Full Load	NO _x , ppmvd @15% O ₂	CO, ppmvd	VOC, ppmvd	NH ₃ ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 - 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_x emissions were achieved with minimal ammonia (NH₃) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_x emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_x reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO_xTM

This technology is an NO_x and CO control system developed by Goal Line Environmental Technologies. Alstom Power was 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 a HRSG.

SCONO_xTM systems were installed at seven sites ranging in capacity from 5 to 43 MW. Alstom Power was not successful in marketing the product at large facilities.

SCONO_xTM technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONO_xTM has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONO_xTM systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO_xTM 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 natural gas reforming unit.

Table 5 contains averaged cost values for SCONOXTM and SCR developed by the California Air Resources Board for their Legislature. 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 5. Cost Comparison between SCR and SCONOX for a 500-MW Unit

Capital Cost (\$)		Annual O&M Cost (\$)	
SCR/CO	SCONO TM	SCR/CO	SCONO TM
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 SCONOXTM multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the SCONOXTM system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by Progress for the proposed project claim slightly greater cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that SCONOXTM is not cost-effective for the present project.

Applicant's NO_x BACT Proposal

The applicant originally proposed a BACT NO_x limit of 2.5 ppmvd @15% O₂. Progress proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. Progress proposed a BACT NO_x emission limit of 10 ppmvd @15% O₂ while burning backup low sulfur fuel oil by a combination of wet injection and SCR.

Department's Draft NO_x BACT Determinations

Table 6 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O₂ on a 1-hour average.

It is noteworthy that the Department has recently issued a draft BACT Determination for FPL Turkey Point Unit 5, establishing 2.0 ppmvd and 8.0 ppmvd as emission limits for gas and oil respectively. The FPL facility is (nearly) adjacent to the Everglades National Park (ENP), and as such, the most stringent emission limits are appropriate. Notwithstanding this, the Department agrees that Progress's proposal of 2.5 ppmvd @15% O₂ on a 24-hour basis and minimization of fuel oil use represents BACT for this project. The limits of 2.5 and 10.0 ppmvd @15% O₂ represent reductions of well over 90% for the gas and oil cases when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 6. Recent NO_x Standards for “F-Class” Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_x Limit ppmvd @ 15% O₂ and Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
Progress Hines PB4	530	2.5 – NG (24-hr) 10 - FO	2x170 MW GE 7FA
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 - FO	4x170 MW GE 7FA & DBs
Progress Hines PB3, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
El Paso Manatee, FL	250	2.5 – NG (24-hr)	175 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs
Enron/Ft. Pierce, FL	~250	3.5 – NG (3-hr) 10 - FO	170 MW MHI 501F

MHI = Mitsubishi Heavy Industries
FO = Fuel Oil

NG = Natural Gas
GE = General Electric

DB = Duct Burner
WH = Westinghouse

PA = Power Augmentation
ABB = Asea Brown Bovari

4.3 CO BACT Determination

CO and VOC Formation and Control Options

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls without an oxidation catalyst, much lower emissions are typically reported for very large combustion turbines (at least for full load operation) without the use of oxidation catalyst.

Based on testing discussed in the NO_x technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Similarly, VOC emissions less than 1 ppm have consistently been measured at new GE7FA units throughout the state. Again the results are roughly equal to those at ANP Blackstone.

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE7FA. Performance guarantees are only now “catching up” with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units. 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.

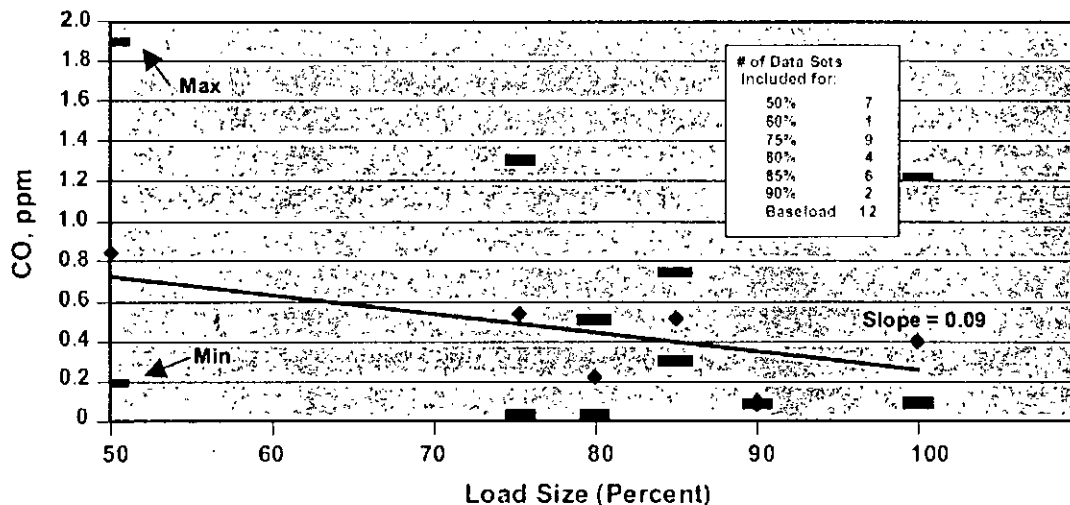


Figure 11. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Low Load and Fuel Oil Considerations

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O₂). The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG. Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC and CO control because of

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destruction by the duct burner. Basically, the claim is that a “3 on 1” configuration (3 CT’s & 1 HRSG) producing 750 MW can be replaced with a “2 on 1” configuration by adding very large Coen “Power Plus” DBs in a Nooter Eriksen HRSG and still produce 750 MW. Basically the capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided. In summary, the installation of duct burners can have the positive effect of *reducing* CO emissions. As noted herein, the proposed project excludes duct burners and power augmentation.

Following is a table with the results of CO and VOC testing recently completed at the Gulf Power Lansing Smith Plant. The units tested were GE7FA combustion turbines (CT) of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine while using duct burners (DB).

Table 7. CO and VOC Emissions - Gulf Power Plant Smith GE 7FA Units (ppmvd@15% O₂)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
Gulf Smith Unit 4 (CT & PA)	5.18	0.61
Gulf Smith Unit 5 (CT & PA)	8.61	0.38

As seen from Table 7, emissions of CO and VOC are very low when the DBs are used and without power augmentation (PA). The Gulf Smith units also provide an example of power augmentation (PA) with the duct burners (DB) off.

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in the Table below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_x control is practiced on all such units when firing fuel oil.

Table 8. CO, VOC Test Results. GE 7FA Gas Turbines firing Fuel Oil. (ppmvd @15% O₂)

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

TECHNICAL EVALUATION AND PRELIMINARY BACT DETERMINATION

Another consideration is “low load” operation. Several operators in Florida installed, will install, or are considering installing oxidation catalyst because: the supplier could not guarantee low CO emissions at medium loads (50 to 70 percent); the units actually exhibited high emissions at such loads; or the units required very long warm-up periods under low load (< 50% and very high CO) conditions. These include Lakeland McIntosh Unit 3, Seminole Payne Creek, Enron Fort Pierce (deferred), and Progress Energy Hines Power Block II and III. This is in contrast to the proposed GE 7FA units that exhibit low CO emissions at 50 percent.

Determinations CO, VOC, and PM/PM₁₀ Emission Limit Determination

The following table is a list of recent CO and VOC (and PM) determinations for project throughout the country. The Progress proposal is included for comparison.

Table 9. CO, VOC, and PM Standards for “F-Class” Combined Cycle Units ¹

Project Location	CO - ppmvd (@15% O ₂)	VOC - ppmv (@15% O ₂)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	1.0	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	1.0 (DB off) 1.7 (DB on))	0.008 (NH ₃ = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	1.0 (DB off) 2.0 (DB on))	0.01
Duke Morro, CA	2.0 (Ox-Cat)	1.15 (DB off) 2.0 (DB on)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	1.4	0.002 (NH ₃ = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	1.0 (DB off) 1.64 (DB on))	0.0048 (NH ₃ = 5 ppmvd) 0.0005 Cool Tower Drift
Progress Hines PB4 (applicant proposal)	8.0 – NG 15.0 – FO	1.3 – NG 3.0 – FO	10.1 lb/hr – NG (Front ½) ² 39.1 lb/hr – FO (Front ½) ²
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	3 – 7.5 lb/hr	0.011
Calpine OEC, PA	10 (1-hr)	1.8	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	1.2	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH ₃ = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH ₃ = 5
Progress Hines PB3, FL	10 - NG (3.5 if Ox-Cat) 20 – FO (7 if Ox-Cat)	2 – NG 10 – FO	10% Opacity NH ₃ = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	1.1 - NG	20 lb/hr – (Front & Back) ² 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/mmBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity

1. FPL Turkey Point draft BACT Determination established co emission limits of 8 ppmvd for gas and oil.
2. Front half means filterable and back half means condensible.

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

Department's CO BACT Proposal

Based on the data available to the Department, Progress's respective proposed CO emission limits for gas and fuel oil firing of 8.0 and 15.0 ppmvd @ 15% O₂ seem slightly high, particularly the proposed oil limit. A detailed cost assessment would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. This cost has been estimated by the applicant at approximately \$7,500 per ton. While the Department does not necessarily accept the estimate, oxidation catalyst is likely not cost-effective for the proposed GE machine.

The Department will set a continuous 24-hr CO limit of 8.0 ppmvd and 12.0 ppmvd (corrected to 15% O₂) for gas and oil-firing, respectively. The proposed VOC emission limits (1.3 ppmvd and 3.0 ppmvd for gas and oil respectively) are adequate to insure that a BACT review is not required; hence the Department accepts them as proposed.

4.4 Sulfur Dioxide (SO₂) and Sulfuric Acid Mist (SAM) BACT Determination

SO₂ control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO₂.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the limited use of low sulfur fuel oil (0.05 percent sulfur) with natural gas as the main fuel. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

The applicant estimated total emissions for the project at 142 tons per year of SO₂ and 21.7 tons per year of sulfuric acid mist. The Department accepts Progress Energy's BACT proposal for SO₂ and SAM.

4.5 Particulate Matter (PM/PM₁₀) BACT Determination and Ammonia (NH₃) Control

PM/PM₁₀ Formation and Control Options

PM and PM₁₀ are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The low sulfur fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 1000 hours per year making any conceivable add-on control technique for PM/PM₁₀ either unnecessary or impractical.

The following table is a summary of PM₁₀ emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.

Table 10. PM₁₀ Emissions from GE 7FA Units (pounds per hour)

<u>Fuel</u>	<u>Range</u>	<u>Average</u>	<u>Std. Deviation</u>
Natural Gas - Front-half (filterable)	0 - 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM₁₀ emission limits are included in Table 9. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_x, SO₂ and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. The NO_x control technology of SCR can increase PM/PM₁₀ emissions from the stack due to formation of ammonium sulfates prior to exiting.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_x control technologies that rely on ammonia injection. Very low values (≤ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH₃ emissions from the Stanton project ranged from 0.1 to 0.9 ppmvd @15% O₂ while firing natural gas. NH₃ and NO_x emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH₃ emissions were 1.5 ppmvd @15% O₂ when firing fuel oil. The Department proposes an ammonia limit during gas firing of 5 ppmvd @15% O₂.

Applicant's PM/PM₁₀ Proposal

Progress proposes PM/PM₁₀ BACT equal to 10.1 pounds per hour (lb/hr, front-half) when firing natural gas. They additionally propose a limit of 39.1 lb/hr (front-half) when firing fuel oil. They also propose an opacity limit of 10% on natural gas (20% on fuel oil).

Department's Draft PM/PM₁₀ BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 1000 hours per year), which shall contain no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average, regardless of fuel.
- Ammonia emissions (slip) shall not exceed 5 ppmvd while firing natural gas.

4.6 Summary of Department Draft BACT Determination

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 11. Draft BACT Determination – Progress Energy Hines Power Block 4

Pollutant	Fuel	Stack Test, 3-Run Average		CEMS Block Average
		ppmvd @ 15% O ₂	lb/hr	ppmvd @ 15% O ₂
CO	Oil	12.0	57.2	12.0, 24-hr
	Gas	8.0	32.1	8.0, 24-hr
NO _x	Oil	10.0	82.4	10.0, 24-hr
	Gas	2.5	17.7	2.5, 24-hr
PM/PM ₁₀	Oil/Gas	Fuel Specifications		
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO ₂	Oil/Gas	2 gr S/100 SCF of gas, 0.05% sulfur fuel oil		
Ammonia	Gas	5	NA	NA

Note: The Department accepts as BACT, the applicant's proposal for natural gas as the exclusively fired fuel in order to control emissions of PM and SO₂ from the auxiliary boiler.

5. NEW SOURCE PERFORMANCE STANDARDS

Small boilers rated at 20 MMBtu per hour as subject to the Federal New Source Standard in Subpart Dc of 40 CFR 60 and 62-296.406 of the Florida Administrative Code. The subject requirements will be specified in the permit.

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

- NO_x (gas) ≤ 110 ppmvd @ 15% O₂ (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_x (oil) ≤ 103 ppmvd @ 15% O₂ (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO₂ emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Hines Energy Center is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NESHAP Subpart YYYYY, which became final on March 5, 2004. According to the final rule, each unit would be considered a "new

lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O₂). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYYY. EPA has stayed the applicability of YYYYY to units such as those proposed for the Hines project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

Based on the same GE technical cited in the Section 4.3 above, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. Progress proposes to meet the limit proposed in YYYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_x technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

7. PERIODS OF EXCESS EMISSIONS

7.1 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.

7.2 Alternate Standards and Excess Emissions Allowed

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.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%),

which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- During any period containing 24 hours of continuous operation, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply on an average basis:
 - NO_x (gas) – 125 lbs/hr
 - NO_x (oil) – 370 lbs/hr
 - CO (gas or oil) – 175 lbs/hr
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

8. AIR QUALITY IMPACT ANALYSIS

8.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM₁₀, CO, NO_x, SO₂, VOC and SAM. PM₁₀, SO₂ and NO_x are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimus monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimus monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimus monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

8.2 Significant Impact Analysis

For PM/PM₁₀, CO, NO_x and SO₂, which have significant impact levels defined for them, a significant impact analysis is performed. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. 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. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas.

If this modeling at worst load conditions show significant impacts, additional modeling, which includes the emissions from surrounding facilities, or multi-source modeling is required to

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determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling. The applicant's initial PM/PM₁₀, CO, NO_x, and SO₂ air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels." These values are tabulated below and compared with the National Ambient Air Quality Standards.

Table 12. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	Significant Impact Level (ug/m ³)	Ambient Air Standards (ug/m ³)	Significant Impact?
SO ₂	Annual	0.04	1	60	NO
	24-Hour	2.7	5	260	NO
	3-Hour	13	25	1300	NO
PM ₁₀	Annual	0.04	1	50	NO
	24-Hour	1.6	5	150	NO
CO	8-Hour	23	500	10,000	NO
	1-Hour	63	2000	40,000	NO
NO ₂	Annual	0.07	1	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective ambient air quality standards. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 118 km to the north. The applicant's initial PM/PM₁₀, NO_x, and SO₂ air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels" for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area.

Table 13. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project Compared with PSD Class I Significant Impact Levels (Chassahowitzka)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m ³)	Class I Significant Impact Level (ug/m ³)	Significant Impact?
PM ₁₀	Annual	0.001	0.2	NO
	24-hour	0.12	0.3	NO
NO ₂	Annual	0.001	0.1	NO
SO ₂	Annual	0.001	0.1	NO
	24-hour	0.17	0.2	NO
	3-hour	0.5	1	NO

8.3 Preconstruction Ambient Monitoring Requirements

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

Table 14. Maximum Project Air Quality Impacts for Comparison to the *de minimus* Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	De Minimus Level (ug/m ³)	Baseline Concentrations (ug/m ³)	Impact Greater Than De Minimus?
PM ₁₀	24-hour	2.5	10	~ 100	NO
NO ₂	Annual	0.1	14	~ 15	NO
SO ₂	24-hour	2.7	13	~ 40	NO
CO	8-hour	23	575	~ 2000	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC. However, the pollutant associated with VOC is actually ozone. Projects exhibiting VOC emissions greater than 100 tons per year (TPY) are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The proposed Power Block 4 project VOC emissions are predicted to be no more than 57 TPY, therefore an analysis, including ambient monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project is an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

8.4 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 Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period

of meteorological data was from 1991 through 1995. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is 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. Since the closest PSD Class I area, the Chassahowitzka National Wilderness Area (CNWA) is greater than 50 km from the proposed facility, 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.

8.5 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife. Very low emissions are expected from this natural gas-fired, with backup fuel oil, combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM₁₀, CO, NO_x and SO₂ 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 project impacts are also less than the significant impact levels for PM₁₀, CO, NO_x, and SO₂, 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.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 4. 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.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m³ of SO₂ for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m³ of SO₂ over a 3-hour period and 4 ug/m³ of SO₂ over a 24-hour period.

The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition.

Impact on Visibility. Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_x, SO₂, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

The Class I Chassahowitzka NWA, where visibility impacts are normally of greater concern, is about 118 kilometers from the proposed site. A regional haze analysis using the CALPUFF model 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 6 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 more 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.

9. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

The Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

In making this preliminary determination, the Department has also included herein a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, or the public.

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NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR Part 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in bold immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

- (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.
- (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.
- (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.
- (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.

§ 60.332 Standard for Nitrogen Oxides.

- (a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:
 - (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:

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

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where:

STD = allowable NOx emissions (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.

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

where:

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

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]

(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.

§ 60.333 Standard for Sulfur Dioxide.

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with the following:

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

[Note: The BACT limits of this permit are more stringent than this requirement.]

§ 60.334 Monitoring of Operations.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

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[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

- (2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

- (c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:
- (1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in this permit.

Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by this permit shall be used to demonstrate compliance with this requirement.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

- (2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

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§ 60.335 Test Methods and Procedures.

- (a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.
- (b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.
- (c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

- (1) The nitrogen oxides emission rate (NO_x) shall be computed for each run using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) (\text{Pr}/\text{Po})^{0.5} e^{19(\text{Ho}-0.00633)} (288^\circ\text{K}/\text{Ta})^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O₂ and ISO standard ambient conditions, volume percent.

NO_{x0} = observed NO_x concentration, ppm by volume.

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.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NO_x monitor required by this permit continuously calculate NO_x emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

- (2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NO_x monitor shall be used to demonstrate compliance with the BACT NO_x limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

- (3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_x emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NO_x emissions using certified CEMS data, provided that compliance be based on a

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minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

- (d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 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 approval of the Administrator.

Department requirement: This permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different analysis methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

- (e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

- G.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.
- G.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 or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
- G.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.
- G.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.
- G.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.
- G.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.
- G.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.
- G.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.

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GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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.

- G.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.
- G.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.
- G.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.
- G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.
- G.13 This permit also constitutes:
- a) Determination of Best Available Control Technology (X)
 - b) Determination of Prevention of Significant Deterioration (X); and
 - c) Compliance with New Source Performance Standards (X).
- G.14 The permittee shall comply with the following:
- a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
 - b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
 - c) Records of monitoring information shall include:
 - 1. The date, exact place, and time of sampling or measurements;
 - 2. The person responsible for performing the sampling or measurements;
 - 3. The dates analyses were performed;
 - 4. The person responsible for performing the analyses;
 - 5. The analytical techniques or methods used; and
 - 6. The results of such analyses.
- G.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.

APPENDIX XS

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

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

Pollutant (Circle One) SO₂ NO_x TRS H₂S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No. : _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period ¹: _____

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

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

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

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

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

Name: _____

Signature: _____ Date: _____

Title: _____

APPENDIX YYYY
NESHAP SUBPART YYYY

APPLICABILITY

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY, which is currently stayed.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003, and it was signed by the Administrator on August 27, 2003. On August 18, 2004 the final rule was stayed (see Federal Register / Vol. 69, No. 159 / Wednesday, August 18, 2004 / Rules and Regulations).

The permittee shall be responsible for ensuring timely compliance with relevant requirements of 40 CFR 63, Subparts A and YYYY.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

P.E. Certification Statement

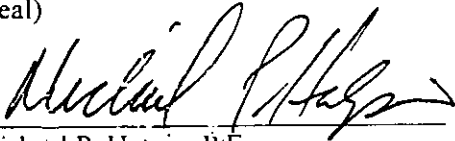
Progress Energy Florida
Hines Energy Complex Power Block 4
Polk County

DEP File No.: PSD-FL-342, PA 92-33
Facility ID No.: 1050234

Project: PSD Permit – Addition of 530 MW combined cycle power

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

(Seal)



Michael P. Halpin, P.E.
Registration Number: 31970

1-6-05
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

P.E. Certification Statement

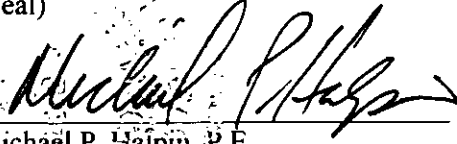
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(Seal)



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New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 	A. Signature <input type="checkbox"/> Agent <input checked="" type="checkbox"/> Addressee
1. Article Addressed to: Mr. Roger Zirkle, Plant Manager Progress Energy Florida - Hines Energy Complex Post Office Box 14042, MAC BB1A St. Petersburg, Florida 33733-4042	B. Received by (Printed Name) C. Date of Delivery
2. Article Number (Transfer from service label) 7000 1670 0013 3110 2219	D. Is delivery address different from item 1? If YES, enter delivery address below: <div style="border: 1px solid black; border-radius: 50%; padding: 10px; display: inline-block; text-align: center;"> ST. PETERSBURG, FL 33733 JAN 20 2005 </div>
PS Form 3811, August 2001	3. Service Type: <ul style="list-style-type: none"> <input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C.O.D. 4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes Domestic Return Receipt 102595-02-M-1540

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

7000 1670 0013 3110 2219

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

Sent To: Mr. Roger Zirkle, Plant Manager

Progress Energy Florida - Hines Energy


Complex

P.O. Box 14042, MAC BB1A

St. Petersburg, Florida 33733-4042

PS Form 3800, May 2000

See Reverse for Instructions

SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 	<p>A. Signature  <input type="checkbox"/> Agent <input type="checkbox"/> Addressee</p> <p>B. Received by (Printed Name) C. Date of Delivery</p>
<p>1. Article Addressed to: Mr. Jammie Hunter Progress Energy Florida Hines Energy Complex Post Office Box 14042, MAC BB1A St. Petersburg, Fl 33733-4042</p>	<p>D. Is delivery address different from item 1? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If YES, enter delivery address below:</p> <div style="border: 1px solid black; border-radius: 50%; width: 100px; height: 100px; text-align: center; margin: 0 auto;"> <p>ST. PETERSBURG, FL JAN 20 2005</p> </div> <p>3. Service Type <input checked="" type="checkbox"/> Certified Mail <input checked="" type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input checked="" type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C.O.D.</p> <p>4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes</p>
<p>2. Article Number (Transfer from service label)</p>	<p>7000 1670 0013 3110 1915</p>

PS Form 3811, August 2001

102595-02-M-1540

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

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

Mr. Jammie Hunter

Sent To
Progress Energy Florida
Post Office Box 14042, MAC BB1A
St. Petersburg, Fl 33733-4042
City, State, ZIP+4

PS Form 3800, May 2000 See Reverse for Instructions

7000 1670 0013 3110 1915