Memorandum

Florida Department of
Environmental Protection

TO: Michael G. Cooke

THRU: Trina Vielhauer
Jeff Koerner

FROM: Michael P. Halpin

DATE: June 6, 2005

SUBJECT: Progress Energy – Hines PB4

Attached for approval and signature is the final PSD permit for the subject facility. The new unit is a combined cycle unit, nearly identical to those at Power Blocks 1-3, with the primary difference being the manufacturer of the CT's. This project was subject to the Power Plant Siting Act (PPSA).

There are no particularly distinguishing characteristics of this power plant addition, except that the applicant had requested permission to fire 0.05% sulfur fuel oil, which is higher in sulfur content than some of the Department's more 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 (case by case) BACT permits this fuel use.

I recommend your approval and signature.

Attachments

/mph

Mike –
This is the version approved by Gov. & Cabinet. We are discussing the philosophies on excess emissions as part of our Appendix CEMS project (EPA noted this in their comments).
Trina

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

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

Permit PSD-FL-342; 1050234-010-AC
Power Plant Siting Case No. PA 92-33
Hines Energy Complex Power Block 4

Enclosed is the Final Permit Number PSD-FL-342. This permit authorizes Progress Energy Florida to construct Power Block 4 at the existing Hines Energy Complex, located in the southwest portion of Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at www.epa.gov/eab.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 6/13/05 to the person(s) listed:

Mr. Jamie Hunter, Progress Energy *
Mr. Scott Osbourn, Golder
Mr. Jim Little, EPA Region 4
Mr. Hamilton Oven, DEP-Siting
Mr. Joel Smolen, DEP-SWD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Mr. Douglas Roberts, HG&S

Clerk Stamp

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

(Clerk) 6/13/05 (Date)

FINAL DETERMINATION

Progress Energy Florida
Hines Power Block 4
DEP File No. 1050234-010-AC, PSD-FL-342

The Department distributed a public notice package on January 18, 2005 to allow the applicant to construct a combined cycle power plant known as Power Block 4 at the Progress Energy Florida Hines Energy Complex located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, in Polk County. The Public Notice of Intent to Issue concerning the Draft Permit was published in the Lakeland Ledger on February 2, 2005.

COMMENTS/CHANGES

No comments were received by the Department from the public.

Comments were received from EPA by letter dated March 2, 2005.

Comments were received from the applicant by letter and electronic correspondence dated March 2, 2005.

The comments are summarized below and the Department's responses are included following each comment. Note that all comments are referenced to Section III - Emissions Unit Specific Conditions of the permit.

Specific Condition 7: The applicant requested that this condition establish CO limits at 3.5/7.0 ppmvd (gas/oil) in the event that an oxidation catalyst is installed. This would be consistent with the similar permitted contingency at Hines Power Blocks 2 and 3.

RESPONSE: The contingency limits of 2.5/5.0 ppmvd (gas/oil) represent values consistent with the current capabilities of oxidation catalysts.

Specific Condition 8: The applicant requested that the maximum heat input for fuel oil should be listed as 2122 MMBtu/hr rather than 2020 MMBtu/hr. The increase is intended to be consistent with Progress Energy's current understanding of the CT's maximum capability firing oil.

RESPONSE: Long-term (annual) emissions are limited by the permitted annual fuel oil (gallons) limitation and potential short-term emissions remain under the SIL's for both Class 1 and 2 areas. Therefore, this request is acceptable.

Specific Condition 9: EPA Region 4 commented that 0.05% sulfur oil was allowed for Hines Energy Complex whereas 0.0015% sulfur oil was determined as BACT for FPL's Turkey Point plant.

RESPONSE: The Department recognizes the above discrepancy between the permit limits for Turkey Point and Hines Energy Complex. However, unlike Hines Energy Complex, FPL's Turkey Point plant lies approximately 20 km from a Class I area., providing the Department with a different set of lenses by which to establish a BACT Determination (see also comments related to condition 10). Additionally, unlike Turkey Point, the Hines Energy Complex currently maintains a large inventory of 0.05% sulfur oil, as it is the only liquid fuel which existing Power Blocks 1, 2 and 3 are permitted to fire. Both issues (above) were given weight in the establishment of 0.05% sulfur oil as BACT for Hines.

Specific Condition 10: EPA Region 4 commented that the NOx and CO limits specified in the draft permit (2.5/10.0 and 8.0/12.0 ppmvd on gas/oil respectively) are not as stringent as the limitations placed upon FPL's Turkey Point plant. Additionally, the applicant has requested that the last sentence of condition 10.c. be denoted as a permitting note.

RESPONSE: As itemized in the Department's response to condition 9, the nearness of Turkey Point to the Class I Everglades N.P. was a factor in developing a most stringent set of BACT limits, yet on a case-by-case basis. However, even beyond this issue, it should be noted that the CO emission limit for natural gas (8.0 ppmvd via CEMS) is identical to that of Turkey Point, without the requirement for an annual test. Additionally, the differing sulfur contents of the permitted fuel oils provided at least one reason for the establishment of different CO emission limits. With regards to the denotation of condition 10.c. as a permitting note, the Department accepts this comment.

Specific Condition 14: EPA Region 4 asked for clarification on how the alternative emission limits relate to the BACT limits itemized in condition 10 as well as the excess emissions allowed by condition 15. Additionally EPA notes that FDEP is inconsistent in the establishment of alternative emission limits, having allowed as many as 6 hours of unlimited emissions in a 24-hour period at FPL's Turkey Point Plant. EPA specifically inquired as to whether this represents a difference in permitting philosophies between the North and South sections. The applicant suggested that for clarification purposes, the alternative limits might be listed as aggregate values rather than average values.

RESPONSE: Regarding EPA's request for clarification, the intent of the alternative emission limits is to reduce the allowance for unlimited excess emissions to 2 hours in a 24-hour period, which is the specified (default) authorization under Florida's state rule. In order to achieve this, a set of limits are established which replace the "normal" BACT limits, for clearly specified operations such as start-up and shut-down. Accordingly, the limits replace those limits identified in condition 10 (for those specified unit operations), yet allow 2 hours of excess emissions via condition 15. Concerning EPA's observation as to a potential difference in permitting philosophies, FDEP will discuss this item internally. Lastly, the Department accepts the applicant's suggestion of aggregate rather than average values.

Specific Condition 15: The applicant requested that the words "unless specifically authorized by the Department for longer duration" be added to the end of the last sentence of this condition.

RESPONSE: The language requested by the applicant was specifically excluded from this condition. As discussed above, the intent of the alternative emission limits is to reduce the allowance for unlimited excess emissions to 2 hours in a 24-hour period, rather than to increase the number of hours of unlimited emissions.

Specific Condition 16: The applicant noted that the underlining found in this condition should be removed and that the alternative emission limits should be excluded from compliance with the 24-hour (CEMS-based) CO and NOx emission limits.

RESPONSE: The Department agrees.

Specific Condition 21: The applicant stated that the gallons of oil calculation is incorrect based upon the values cited in its application.

RESPONSE: The Department agrees.

Specific Condition 22: The applicant requested that a clarifying statement be added to the end of condition 22.f eliminating those hours within the alternative emission standard from compliance within the 24-hour block emission rate values. The applicant additionally suggested that the comment concerning water injection should be removed.

RESPONSE: The Department agrees.

Specific Condition 26: The applicant requested that a caveat should be written into this condition allowing for more recent and equivalent ASTM methods to be utilized in determining fuel sulfur content.

RESPONSE: The Department agrees.

Specific Condition 28: The applicant suggested that the reference to Subpart GG emission limits should be double-checked for accuracy.

RESPONSE: The Department accepts this comment but believes the reference to be correct.

General Comment: The applicant requested that language be added in the "Emission Performance Testing" portion of the permit as follows:

Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

RESPONSE: The language proposed essentially raises the ammonia slip limit from 5 to 7 ppm and seemingly eliminates the possibility of a violation.

Section IV: The applicant requested that the heat input limit of the auxiliary boiler be revised upward from 20 MMBtu/hr to 99 MMBtu/hr.

RESPONSE: The Department accepts this request, as it does not trigger any further regulatory requirements.

CONCLUSION

The draft permit was presented, with the recommended changes identified above, to the Division of Administrative Hearings (Administrative Law Judge Charles A. Stampelos) within a Site Certification hearing, held on March 23, 2005 in Bartow, Florida. On April 5, 2005 Judge Stampelos issued a Recommended Order that the Governor and Cabinet, sitting as the Siting Board, enter a Final Order granting certification to construct and operate Hines Power Block 4. On June 1, 2005, the Siting Board heard the case, and on June 8, 2005 Governor Bush signed the above-referenced Final Order.

Therefore, the final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

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

Michael G. Cooke | 6/10/05

Michael Cooke, Director
Division of Air Resource Management

(Date)

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/PM_{10}), sulfur dioxide (SO_2), 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

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

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.]

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/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx 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 NOx 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. Nominal heat input values are 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	Nominal Heat Input (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 NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, PM/PM_{10}, sulfuric acid mist (SAM) and SO_2. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. 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.]

3. National Emission Standards for Hazardous Air Pollutants (NESHAP): The Department determines that compliance with the stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY (currently stayed) is required. See Appendix YYYY of this permit.

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 2,122 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

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 [g]	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* *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 NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx 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. *{Permitting Note: 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/PM_{10} 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 SO_2 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,*
- *NOx = 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,*
- *PM_{10} = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*
- *SO_2 = 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 SO_2 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

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 24 hour period, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply:

a) An alternative NOx limit of 3000 lb shall apply if natural gas is the exclusively fired fuel;

b) An alternative NOx limit of 8880 lb shall apply if any fuel oil is fired; and

c) An alternative CO limit of 4200 lb shall apply when firing either natural gas of 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 certain periods may be excluded from the compliance determination calculation requirements 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. 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.

c. Data collected during periods covered by the alternate emissions standard provisions of Condition No.14 may be excluded from the compliance determination calculation requirements of Condition No. 10.

[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.]

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	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (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	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

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/PM_{10} 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.

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 6,140,000 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. <u>CEMS</u>: 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 (CO_2) 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 CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

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 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 CO_2 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 NOx 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% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the 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

comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx 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 NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and

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)]

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 99 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 99 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 SO_2 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
FINAL 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

June 6, 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 YYYY, 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/PM_{10}), sulfur dioxide (SO_2), 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

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/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 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-NOx (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:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
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.

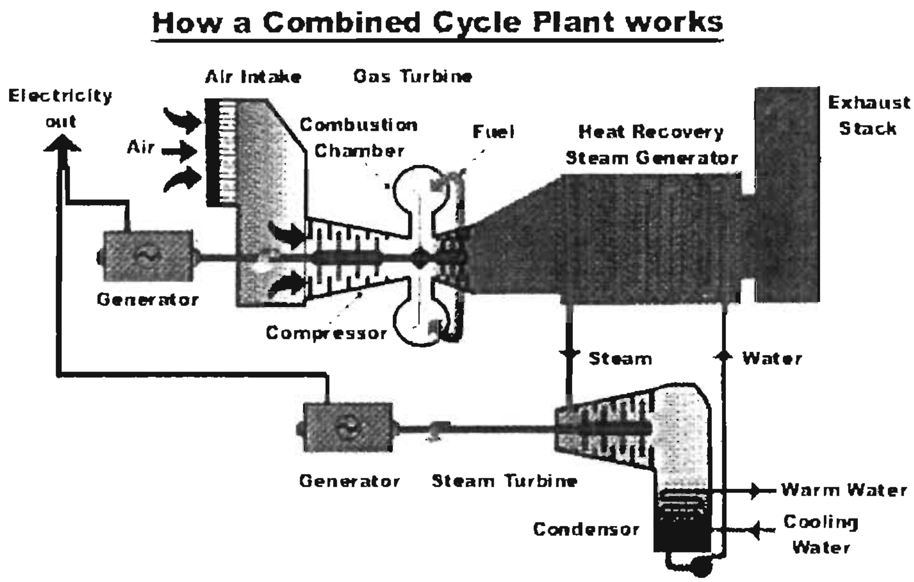

Figure 4. Key Components of a Combined Cycle Unit

2.3 Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), 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, SO_2, SAM and PM/PM_{10}.

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 <u>BACT Determination Procedure</u>

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.

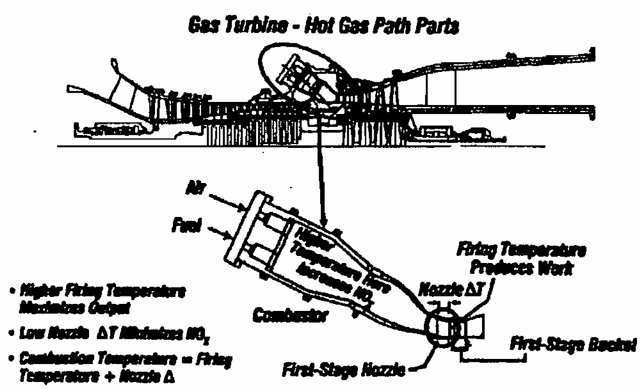

Figure 5 – Relation between Flame Temperature and Firing Temperature

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% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 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%O_2. 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.

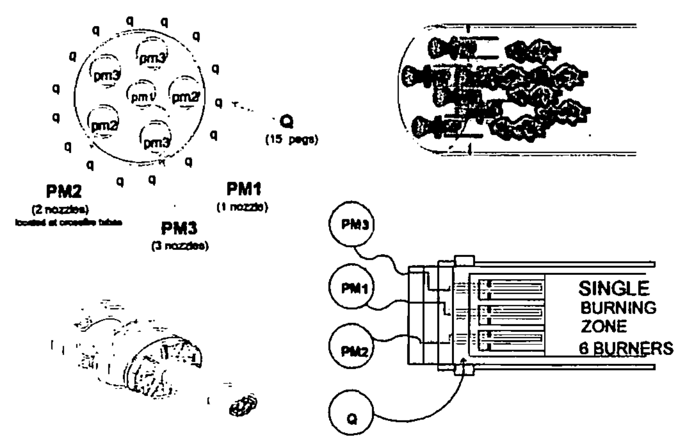

Figure 6 – DLN-2.6 Fuel Nozzle Arrangement

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.

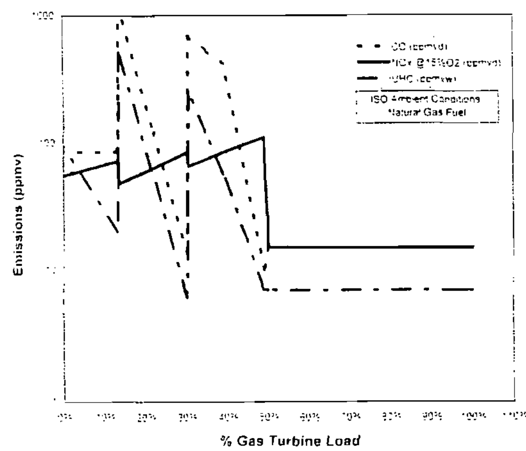

Figure 7 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

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.

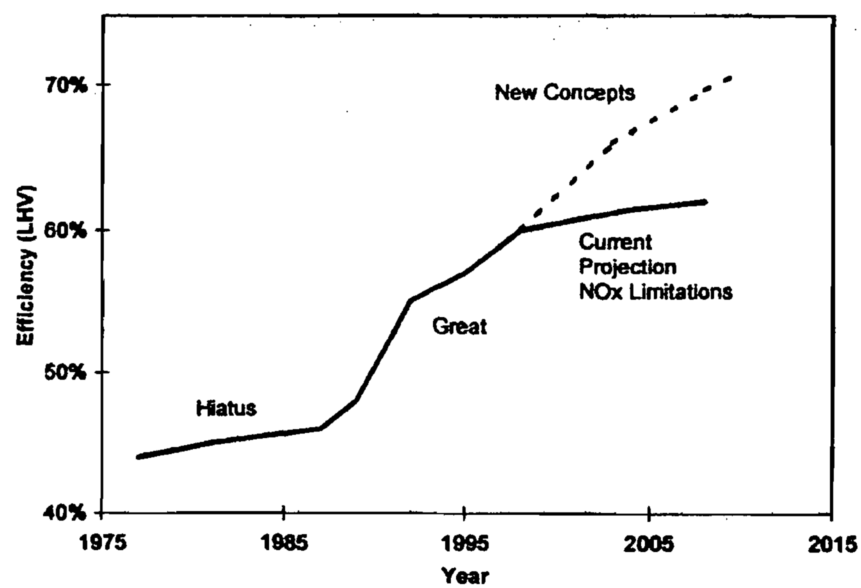

Figure 8 – Efficiency Increases in Combustion Turbines

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™. 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% O_2 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%O_2 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.

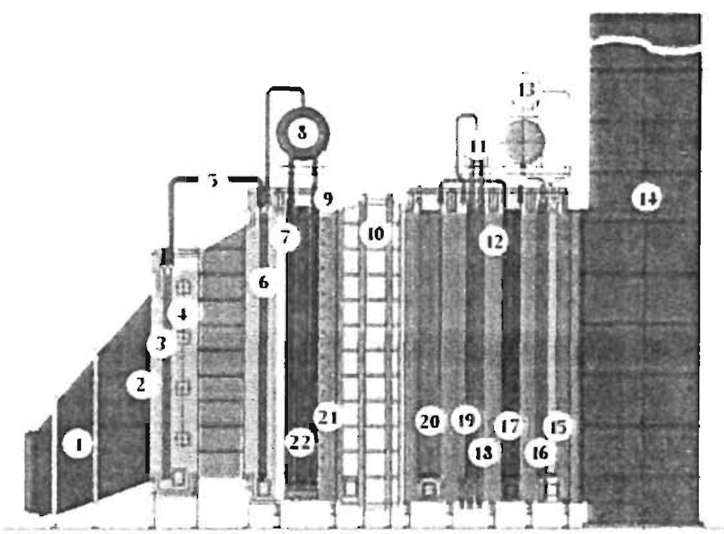

Figure 9 – Key HRSG Components (10 is SCR)

Figure 10 – Hines Power Block 1

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% O_2 (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 (NH_3) 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%.

$SCONO_X$™

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.

$SCONO_X$™ 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.

$SCONO_X$™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, $SCONO_X$™ 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 SCONO$_X$™ 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 SCONO$_X$ for a 500-MW Unit

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

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with SCONO$_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the SCONO$_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

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 SCONO$_X$™ 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% O_2. 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% O_2 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% O_2 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% O_2 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% O_2 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% O_2 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 NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse 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.

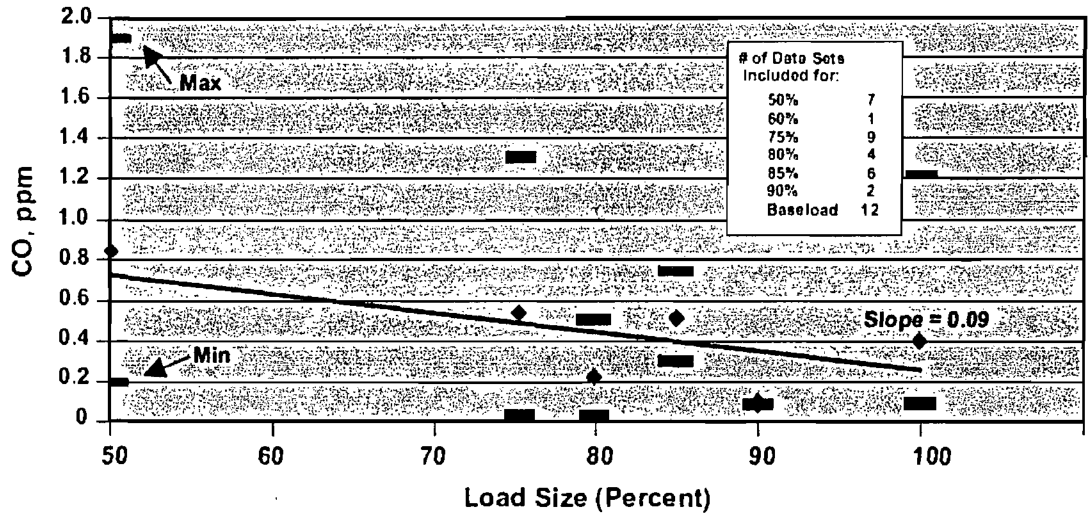

Figure 11. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

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% O_2). 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 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% O_2)

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% O_2)

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

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/PM_{10} 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% O_2 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% O_2) 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 (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

SO_2 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 SO_2.

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 SO_2 and 21.7 tons per year of sulfuric acid mist. The Department accepts Progress Energy's BACT proposal for SO_2 and SAM.

4.5 Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} 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/PM_{10} either unnecessary or impractical.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.

Table 10. PM_{10} Emissions from GE 7FA Units (pounds per hour)

Fuel	Range	Average	Std. Deviation
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/PM_{10} 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, SO_2 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/PM_{10} 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 ($\leq$ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH_3 emissions from the Stanton project ranged from 0.1 to 0.9 ppmvd @15% O_2 while firing natural gas. NH_3 and NO_X emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH_3 emissions were 1.5 ppmvd @15% O_2 when firing fuel oil. The Department proposes an ammonia limit during gas firing of 5 ppmvd @15% O_2.

<u>Applicant's PM/PM_{10} Proposal</u>

Progress proposes PM/PM_{10} 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).

<u>Department's Draft PM/PM_{10} BACT Determinations</u>

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 ($\leq$ 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% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_X (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 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 YYYY, 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% O_2). 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 YYYY. EPA has stayed the applicability of YYYY 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 YYYY 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 YYYY 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/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 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/PM_{10}, CO, NO_X and SO_2, 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

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/PM_{10}, CO, NO_X, and SO_2 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 4 Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m³)	Significant Impact Level (ug/m³)	Ambient Air Standards (ug/m³)	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/PM_{10}, NO_X, and SO_2 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 4 Project Compared with PSD Class I Significant Impact Levels (Chassahowitzka)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m³)	Class I Significant Impact Level (ug/m³)	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 PM_{10}, CO, NO_X and SO_2 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 PM_{10}, CO, NO_X, and SO_2, 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/m^3 of SO_2 for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 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, SO_2, 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.

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.

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.

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:

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

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).

<u>Department requirement</u>: **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.

<u>Department requirement</u>: **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.**

[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.

§ 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 (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

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

NOxo = observed NOx 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 H_2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

__Department requirement__: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx 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 NOx monitor shall be used to demonstrate compliance with the BACT NOx 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 NOx 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 NOx emissions using certified CEMS data, provided that compliance be based on a

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.]

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)* SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer: ______________________

Model No. : ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

Total source operating time in reporting period [1]: ______________________

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

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

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

Note: On a separate page, describe any changes since 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: ______________________

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.]

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Jamie Hunter
Progress Energy Florida
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X MN ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) C. Date of Delivery

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

ST. PETERSBURG FL 33733
JUN 15 2005
POSTAL SERVICE

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

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

2. Article Number
(*Transfer from service label*) 7001 0320 0001 3692 2954

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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

7001 0320 0001 3692 2954

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

Postmark
Here

T

Mr. Jamie Hunter
Progress Energy Florida
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

Ser

Stre
or F

City

PS Form 3800, January 2001 See Reverse for Instructions

BEST AVAILABLE COPY

SENDER: COMPLETE THIS SECTION

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

1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida-Hines Energy Complex
100 Central Avenue, CX1B
St. Petersburg, Florida 33701

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) M. H. Moloca C. Date of Delivery 6/15/05

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

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 0320 0001 3692 2978

PS Form ... Return Receipt 102595-02-M-1540

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

7001 0320 0001 3692 2978

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

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida-Hines Energy Complex
100 Central Avenue, CX1B
St. Petersburg, Florida 33701

PS Form 3800, January 2001 See Reverse for Instructions

Progress Energy

February 10, 2005

Mr. Michael Halpin, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Halpin:

Re: **Hines Energy Complex - Power Block 4**
PSD/Air Construction Permit Application
File No. 1050234-010-AC
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published in the Lakeland Ledger on February 2, 2005.

Please contact me at (727) 820-8764 if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Enclosure

c(w/enc): Hamilton Oven, FDEP Siting - Tallahassee

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared C. Morgan Miller, who on oath says that he is Display Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being an

Public Notice of Intent

....

in the matter **Hines Energy Complex at Power Block 4**...................

....

....

Concerning **Project No. 1050234-010-AC** ....

....

was published in said newspaper in the issues of **2-2; 2005**...............

....

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed......C. Morgan Miller
C. Morgan Miller
Display Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 2nd ....

day of February .... A.D. 20 05 ....

Patricia Ann Rouse
Notary Public

(Seal) PATRICIA ANN ROUSE
MY COMMISSION # DD 330015
EXPIRES: October 17, 2008
Bonded Thru Notary Public Underwriters

My Commission Expires Oct 17, 2008
M119

Attach Ad Here

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 7miles south-southwest of Bartow and 5miles west-northwest of Fort Meade

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks1 and 2) and another electrical generating unit currently under construction (Power Block3). Power Block1 is a 500MW 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 Block3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530MW power generation unit. After completion of this project (Power Block4), the plant will have a total generating capacity of approximately 2,090MW
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.

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Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all e-mail 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 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.

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Mediation: Mediation is not available in this proceeding

M119 2-2, 2005

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared C. Morgan Miller, who on oath says that he is Display Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being an

Public Notice of Intent

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in the matter **Hines Energy Complex at Power Block 4**....................

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Concerning **Project No. 1050234-010-AC** ....

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was published in said newspaper in the issues of **2-2; 2005**................

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Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed........C. Morgan Miller
C. Morgan Miller
Display Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 2nd ....

day of February.............. A.D. 20 05 ....

Patricia Ann Rouse
Notary Public

(Seal) PATRICIA ANN ROUSE
MY COMMISSION # DD 330015
EXPIRES: October 17, 2008
Bonded Thru Notary Public Underwriters

My Commission Expires Oct 17, 2008

M119

Attach Ad Here

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 7miles south-southwest of Bartow and 5miles west-northwest of Fort Meade.

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks1 and 2) and another electrical generating unit currently under construction (Power Block3). Power Block1 is a 500MW 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 Block3, when complete, will include 2 combustion turbines, 2 HRSGs and 1 steam turbine in a 530MW power generation unit. After completion of this project (Power Block4), the plant will have a total generating capacity of approximately 2,090MW
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M119 2-2; 2005

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Case No ....

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Public Notice of Intent

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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.

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Mediation: Mediation is not available in this proceeding.

M119 2-2; 2005

Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer

THRU: J. K. Pennington JKP

FROM: M. P. Halpin

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

Department of Environmental Protection

Jeb Bush
Governor

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 L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TV/jp/mh

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

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 L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary 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.

[signature]	1/18/05
(Clerk)	(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.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. 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 Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate 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.

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 e-mail 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 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 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

Michael Cooke, Director (Date)
Division of Air Resource Management

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/PM_{10}), sulfur dioxide (SO_2), 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

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

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.]

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/PM_{10}, SAM, SO_2 and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx 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 NOx 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 NOx emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: Determinations of BACT were made for CO, NOx, PM/PM_{10}, sulfuric acid mist (SAM) and SO_2. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. <u>New Source Performance Standards (NSPS)</u>: 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.]

3. <u>National Emission Standards for Hazardous Air Pollutants (NESHAP)</u>: The Department determines that compliance with the stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY (currently stayed) is required. See Appendix YYYY of this permit.

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

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 [g]	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* *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 NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx 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/PM_{10} 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 SO_2 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,*
- *NOx = 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,*
- *PM_{10} = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*
- *SO_2 = 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 SO_2 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

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 of 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.]

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	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (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	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

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/PM_{10} 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.

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 (CO_2) 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 CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

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 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 CO_2 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 NOx 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% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the 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

comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx 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 NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and

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)]

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 SO_2 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.

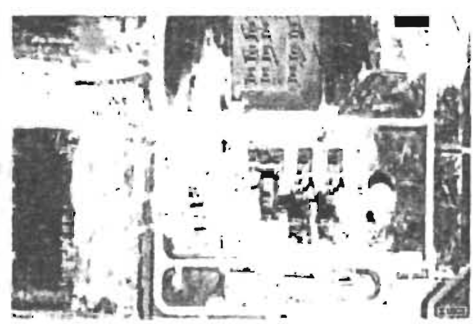

FIGURE 1 – Facility Location **FIGURE 2 – Satellite Image** **FIGURE 3 – 1999 Close-up**

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 YYYY, 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/PM_{10}), sulfur dioxide (SO_2), 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 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/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 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-NOx (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:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
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.

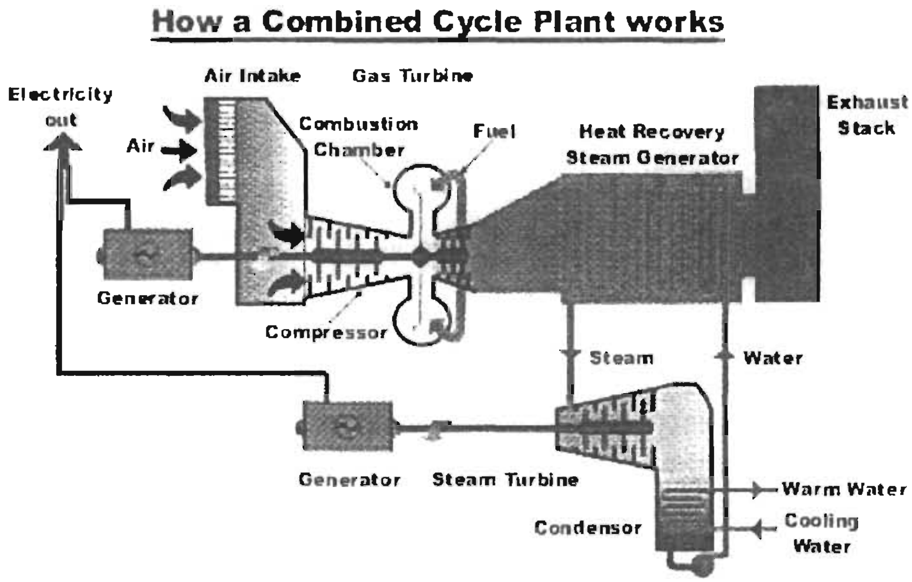

Figure 4. Key Components of a Combined Cycle Unit

2.3 Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), 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, SO_2, SAM and PM/PM_{10}.

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.

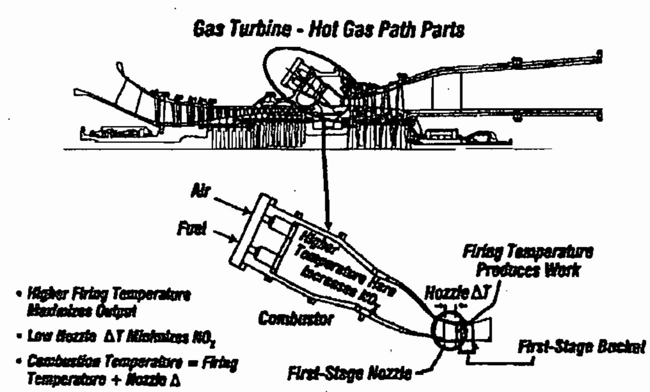

Figure 5 – Relation between Flame Temperature and Firing Temperature

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% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 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%O_2. This constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

<u>Descriptions of Available NO_X Controls</u>

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.

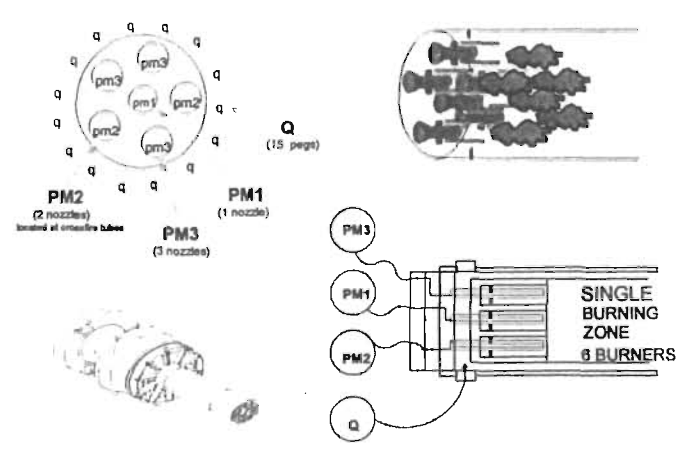

Figure 6 – DLN-2.6 Fuel Nozzle Arrangement

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.

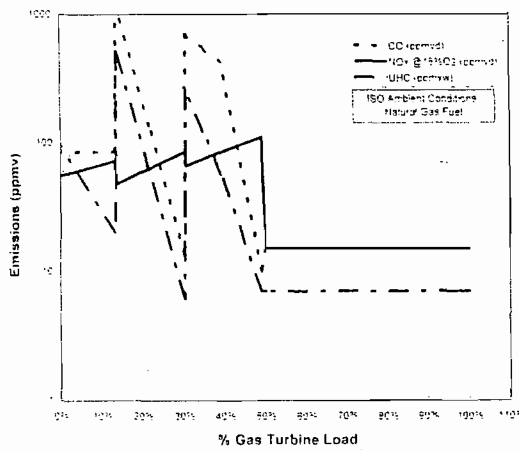

Figure 7 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

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.

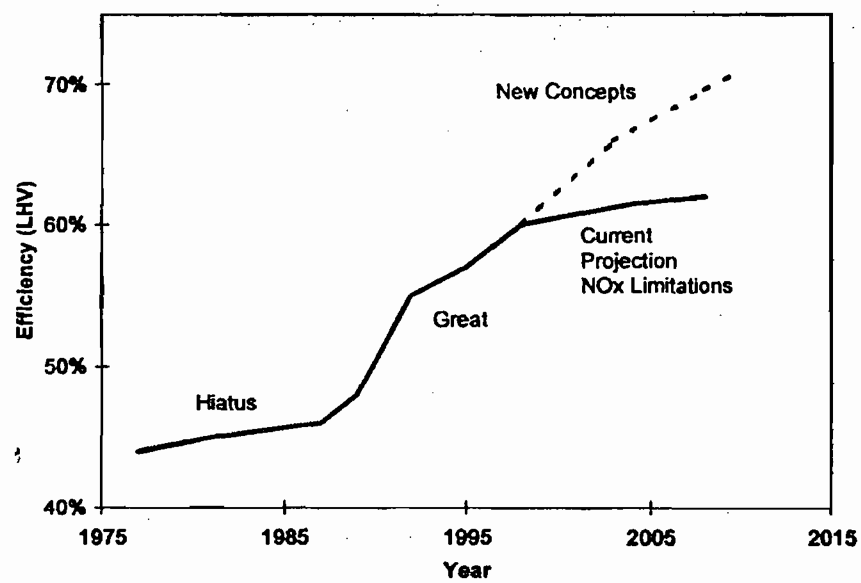

Figure 8 – Efficiency Increases in Combustion Turbines

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™. 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% O_2 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%O_2 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.

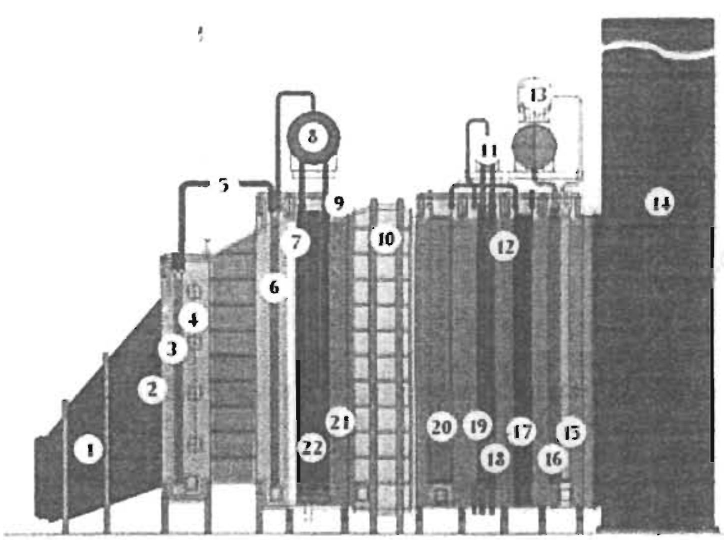

Figure 9 – Key HRSG Components (10 is SCR)

Figure 10 – Hines Power Block 1

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% O_2 (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 (NH_3) 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%.

$SCONO_X$™

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.

$SCONO_X$™ 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.

$SCONO_X$™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, $SCONO_X$™ 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 $SCONO_X$™ 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 $SCONO_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X$™	SCR/CO	$SCONO_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with $SCONO_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the $SCONO_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

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 $SCONO_X$™ 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% O_2. 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% O_2 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% O_2 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% O_2 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% O_2 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% O_2 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 NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse 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.

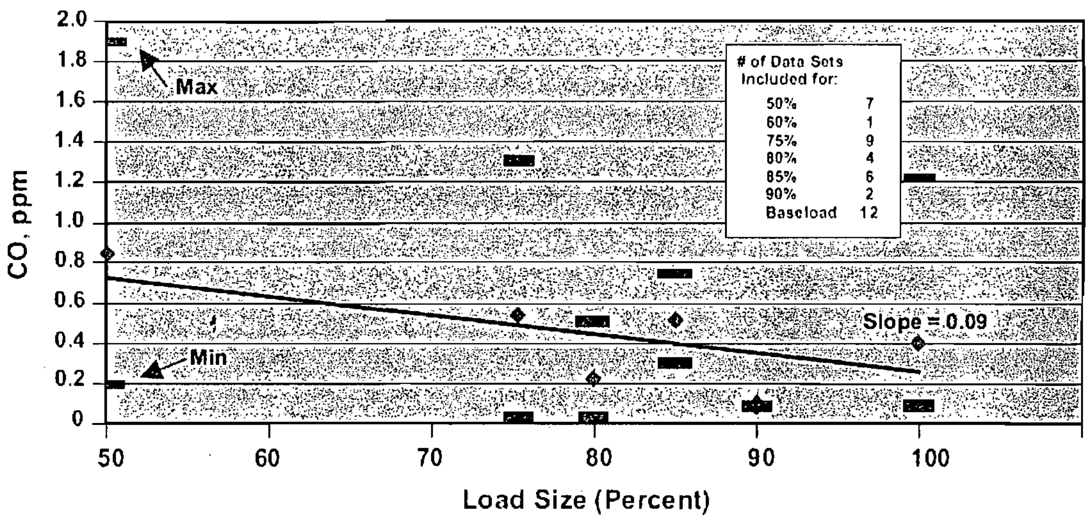

Figure 11. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

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% O_2). 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 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% O_2)

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% O_2)

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

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/PM_{10} 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% O_2 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% O_2) 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 (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

SO_2 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 SO_2.

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 SO_2 and 21.7 tons per year of sulfuric acid mist. The Department accepts Progress Energy's BACT proposal for SO_2 and SAM.

4.5 Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} 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/PM_{10} either unnecessary or impractical.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.

Table 10. PM_{10} Emissions from GE 7FA Units (pounds per hour)

Fuel	Range	Average	Std. Deviation
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/PM_{10} 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, SO_2 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/PM_{10} 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 ($\leq$ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH_3 emissions from the Stanton project ranged from 0.1 to 0.9 ppmvd @15% O_2 while firing natural gas. NH_3 and NO_X emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH_3 emissions were 1.5 ppmvd @15% O_2 when firing fuel oil. The Department proposes an ammonia limit during gas firing of 5 ppmvd @15% O_2.

Applicant's PM/PM_{10} Proposal

Progress proposes PM/PM_{10} 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/PM_{10} 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 ($\leq$ 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% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_X (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 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 YYYY, 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% O_2). 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 YYYY. EPA has stayed the applicability of YYYY 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 YYYY 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 YYYY 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/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 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/PM_{10}, CO, NO_X and SO_2, 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

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/PM_{10}, CO, NO_X, and SO_2 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/PM_{10}, NO_X, and SO_2 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 PM_{10}, CO, NO_X and SO_2 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 PM_{10}, CO, NO_X, and SO_2, 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/m^3 of SO_2 for 8 hours. This proposed project is predicted to have a maximum impact of 17 ug/m^3 of SO_2 over a 3-hour period and 4 ug/m^3 of SO_2 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, SO_2, 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.

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:

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

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).

<u>Department requirement</u>: **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.

<u>Department requirement</u>: **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.**

[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.

§ 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 (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

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

NOxo = observed NOx 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 NOx monitor required by this permit continuously calculate NOx 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 NOx monitor shall be used to demonstrate compliance with the BACT NOx 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 NOx 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 NOx emissions using certified CEMS data, provided that compliance be based on a

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.]

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.

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.

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)* SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer: ______________________

Model No. : ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

Total source operating time in reporting period [1]: ______________________

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

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

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

Note: On a separate page, describe any changes since 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: ______________________

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

Progress Energy Florida
Hines Energy Complex Power Block 4
Polk County

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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

SENDER: COMPLETE THIS SECTION

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

1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida -
Hines Energy Complex
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) | C. Date of Delivery

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

ST. PETERSBURG, FL 33733
JAN 20 2005
CALLER SERVICE

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 2219

PS Form 3811, August 2001 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
Street, Apt. No.; or PO Box No.
Complex
City, State, ZIP+4
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 items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Jammie Hunter
Progress Energy Florida
Hines Energy Complex
Post Office Box 14042, MAC BB1A
St. Petersburg, Fl 33733-4042

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Milt
☐ Agent
☐ Addressee

B. Received by (*Printed Name*)

C. Date of Delivery

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

ST. PETERSBURG, FL 33733
JAN 20 2005
POSTAL SERVICE

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

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

2. Article Number (*Transfer from service label*) 7000 1670 0013 3110 1915

PS Form 3811, August 2001 102595-02-M-1540

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

7000 1670 0013 3110 1915

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

Postmark Here

Sent To
Mr. Jammie Hunter
Progress Energy Florida
Street, Apt. No.; or PO Box No.
P.O. Box 14042, MAC BB1A
City, State, ZIP+4
St. Petersburg, Fl 33733-4042

PS Form 3800, May 2000 See Reverse for Instructions

Progress Energy

RECEIVED

DEC 06 2004

BUREAU OF AIR REGULATION

December 1, 2004

Mr. Michael Halpin, P.E.
North Permitting Section
DARM/BAR
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

RE: DRAFT PSD PERMIT NO. 1050234-010-AC
HINES ENERGY COMPLEX, POWER BLOCK 4

Dear Mr. Halpin:

Progress Energy Florida (PEF) is in receipt of your letter dated August 19, 2004. The letter indicates that the Department has begun review of our recent PSD application for the above-referenced facility. The Department has deemed the application incomplete due to the need for additional information. In addition, in a letter to the Department, dated November 4, 2004, PEF provided notification that a decision was made to use combustion turbines other than those generally represented in the original permit application. To more accurately describe the project, as it stands today, this letter also serves to transmit amended permit application forms (Attachment 1), revised emission tables (Attachment 2) and revised BACT tables for CO and NOx (Attachment 3).

The Department's requests and comments, per the August 19, 2004 letter, are addressed below in the order in which they were received.

DEP Comment

Progress has requested permission to operate for up to 3,000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.

A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.

B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.

C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).

D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80%, and 100%).

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

Response

As indicated above, during final equipment selection for this project, a decision was made to use combustion turbines other than those generally represented in the original permit application. The characteristics of the combustion turbine model selected (GE 7FA) are slightly different than those upon which the original application was based (SW 501F). The GE 7FA turbine model is able to meet defined emission characteristics within a load range of 50 to 100 percent of rated load on both fuels. The amended permit application, submitted in conjunction with this letter, provides data sufficient to address the Department's above comments.

Comparisons of the stack, operating, and emission data for natural gas-firing and distillate oil-firing for the GE 7FA combustion turbine to those for the SW 501F combustion turbine are presented in Tables 1 and 2, respectively. Details of the design information and stack parameters for the GE 7FA combustion turbines are presented in revised Tables A-1 to A-29 of Appendix 10.1.5 of the Site Certification Application (SCA). Information for firing natural gas in the combustion turbines are presented in Tables A-1 to A-12 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. Information for firing distillate fuel oil in the combustion turbines are presented in Tables A-13 to A-24 for 100%, 75%, and 50% loads at ambient temperatures of 20°F, 59°F, and 95°F. A summary of the maximum potential annual emissions for the two combustions turbines and one auxiliary boiler is presented in Table A-25. Supporting information for estimating formaldehyde emissions for the combustion turbines is presented in Tables A-26 to A-28. Finally, emission estimates for the auxiliary boiler are presented in Table A-29.

In general, PEF is requesting that no restrictions be placed on operations at any load, since continuous emissions monitoring of both NOx and CO will be performed. Demonstration of continuous compliance with these parameters is sufficient to restrict the overall operation of the unit.

Based on the maximum annual emissions presented in Table A-25, there will be a decrease in annual emissions for all pollutants except sulfur dioxide (SO_2) and nitrogen oxides (NO_x). For SO_2 and NO_x, the maximum increase in annual emissions are about 5 and 4 TPY, respectively, from those presented in the SCA. The increases in those pollutant emissions are primarily due to oil-firing. No additional Prevention of Significant Deterioration (PSD) review requirements will be triggered with the GE 7FA combustion turbines and auxiliary boiler. In fact, the volatile organic compound (VOC) emissions are estimated to be below the PSD significant emission rate of 40 TPY, requiring no PSD review for that pollutant.

In addition, no additional air quality impact analyses are required for the project with the GE 7FA combustion turbines since the air quality impacts for these turbines are expected to be similar to or lower than those predicted for the SW 501F combustion turbines. The exhaust gas flow rates, velocities, and temperatures for each combination of operating load and ambient temperature are higher for the GE 7FA turbines than those for the SW 501F turbines, resulting in more dilution and dispersion of the sources' plumes for the GE turbines. It should be noted that while the stack height remains the same for the GE turbine, the stack diameter is slightly smaller than that of the SW turbine (18 ft compared to 19 ft).

For natural gas-firing, since the maximum hourly emissions for the GE turbines are equal to or less than those for the SW turbines, the air quality impacts for the GE turbines will be lower than those for the SW turbines. For distillate oil-firing, the maximum hourly emissions for the GE turbines are also lower than those for the SW turbines except for SO_2 and NO_x. For SO_2, the maximum hourly emissions increase from about 3 percent at 20°F to 8 percent at 95 °F. For NO_x, the maximum hourly emissions increase from about 5 percent at 59°F to 8 percent at 95 °F. Even if the maximum air quality impacts for these pollutants were increased by 8 percent and no account was made for the increased exhaust gas flow rates and temperatures associated with the GE turbines, the air quality impacts for the GE turbines would still remain below the PSD Class II and I significant impact levels shown in Tables 5.6.1.-1 and 5.6.1-2 of the SCA (see also Tables 7-1 and 7-2 in Appendix 10.5.1). In addition, the 24-hour average visibility impairment and sulfur and nitrogen deposition predicted for the project are also expected to be below the trigger criteria that would require additional analyses (see Tables 8-5 and 8-6 in Appendix 10.5.1).

DEP Comment

Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours.'

A) Based upon prior guidance from EPA Region 4, the department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department is will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up). The Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.

B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours,) by providing:

1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

Response

As the Department has indicated above, the development of alternative emission limits to address periods of non-routine operations, such as startup/shutdown is acceptable. PEF withdraws its request for allowable hours of excess emissions during startup/shutdown periods, contingent upon the development of acceptable alternative emission limits that cover these periods of operation. PEF requests the following alternative emissions limits, based on a 24-hour average:

NOx (gas): 125 lbs/hour
NOx (oil): 370 lbs/hour

CO (gas & oil): 175 lbs/hour

DEP Comment

Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines". In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

Response

As previously indicated, PB 4 will be employing GE 7FA combustion turbines. GE was contacted and requested to address the Department's comment. Their response is provided as Attachment 4 to this letter.

DEP Comment

Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:
   1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
   2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
   3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should exclude the initial cost of the catalyst (times freight and sales tax).
   4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated net TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton.

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton.

Response

A) While PEF is not proposing to install a CO catalyst, the power block will be constructed with space available to accommodate the installation of a CO catalyst, if required in the future. The proposed location to accommodate the potential future addition of a CO catalyst is within the HRSG, immediately prior to the SCR section.

B-1) The Indirect Costs for CO catalyst cost analysis have been revised to be a percentage of the Total Direct Capital Costs (TDCC). The CO catalyst cost analysis has also been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised CO cost analysis (Tables B-8 to B-11) are included as Attachment 3 to this letter.

B-2) The "Inventory Cost" associated with the Catalyst Replacement Cost has been removed from the Annualized Cost Table.

B-3) The catalyst and the catalyst support system have different life expectancies, 3 years and 15 years, respectively. Therefore, the annualized cost for CO catalyst has been revised to reflect a capital recovery of 7% for 15 years for the "Total Direct, Indirect, and Capital" costs for the CO catalyst system minus the capital cost, sales tax, and shipping cost of the catalyst.

A separate annual cost for the catalyst has been estimated based on a capital recovery of 7% for 3 years, based on the life expectancy of the catalyst.

B-4) The addition of a CO catalyst adds back pressure to the system resulting in decreased MW output of the CT Unit. The CO catalyst is estimated to decrease the output by 0.2%, resulting in a corresponding 0.2% decrease in electricity sales. Based on a rated 181.7 MW CT output, the result is a loss of $159,170 per year. This loss is based on $0.05/kW per EPA's OAQPS Control Cost Manual.

In addition, a heat rate penalty of 0.2% results from the CO catalyst. Based on a heat input of 1,806 MMBtu/hr and an updated fuel cost of $6/MMBtu (see Attachment 5), the result is an additional fuel cost of $189,850 per year. Therefore, the total "Heat Rate Penalty" is equal to the loss in MW output plus the loss in heat input and is approximately $350,000 per year.

C) As stated previously, the CO catalyst cost analysis has been revised to reflect final equipment selection of GE 7FA combustion turbines. The revised cost effectiveness, based on GE CTs, is estimated to be $6,500 per ton CO removed. Reduced baseline CO emissions from the GE CTs compared to the Siemens Westinghouse CTs (9 ppmvd vs. 12 ppmvd and 20 ppmvd vs.30 ppmvd for gas and oil firing, respectively) result in a significantly higher cost effectiveness for GE Units. The basis for estimating the net TPY of CO removed resulting in the revised GE cost effectiveness of $6,500 per ton is as follows:

1. Uncontrolled Emissions = 148 TPY
    i. 9 ppmvd gas firing
    ii. 29.7 lb/hr gas firing, for 7,760 hour per year
    iii. 20 ppmvd oil firing
    iv. 66 lb/hr oil firing, for 1,000 hours per year
2. Controlled Emissions = 29 TPY
    i. 2.0 ppmvd gas firing
    ii. 80.5 % reduction

D) The basis for estimating the net TPY of CO removed that results in the revised GE cost effectiveness of $7,500 per ton is the total incremental emissions from Table B-11 equal to 103.5 TPY. The 103.5 TPY emissions include reduction of CO emissions and increase in PM, NO_x, and SO_2 emissions.

Attachment 3 also presents updated SCR and $SCONO_x$ cost analysis tables to reflect the final equipment selection of GE 7FA combustion turbines. As shown in Tables B-3 through B-6, the cost effectiveness of SCR with GE 7FA CTs is higher than the previously submitted Siemens Westinghouse CT analysis. The cost effectiveness is higher in GE CTs due to lower baseline emissions on gas (9 ppmvd for GE compared to 25 ppmvd for Siemens Westinghouse). As a result, the NO_x BACT analysis conclusions remain the same and are as follows:

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NOx emissions level using this technology is 2.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 10 ppmvd corrected to 15 percent O_2 when firing distillate fuel oil. This combination of technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts, given the recent BACT decisions on other similar projects.

The project also includes the addition of a 20 MMBtu/hr gas-fired auxiliary boiler. The auxiliary boiler will fire natural gas only and will be used primarily for cold startup of the combustion turbines. The auxiliary boiler will operate less than 500 hours per year. The emissions from the boiler are a result of the combustion process and trace elements in the fuel. Based on the size of the unit and expected annual operation, there are no technically or economically feasible methods for controlling emissions other than the inherent quality of the fuel. Therefore, BACT for the proposed auxiliary boiler is based on fuel quality specs and limiting operation to no more than 500 hours per year.

DEP Comment

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Response

As PEF has received no additional comments, it's our understanding that the EPA and the NPS have no further comments on the original application.

DEP Comment

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-213.420(1)(b), F.A.C., requires applicants to respond to requests for information within 90 days, unless the applicant has requested in writing, and has been granted, additional time within 90 days.

Response

In a letter to the Department, dated November 4, 2004, PEF had requested, and was granted, an extension of the 90 day timeframe, until December 3, 2004. This response, submitted within the approved timeframe, along with the associated permit application form revisions, signed and certified by a Florida PE, addresses the above comment.

PEF appreciates you consideration of the above responses. If you should have any questions, please don't hesitate to contact me at (727) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Attachment

cc: Jim Pennington, FDEP- DARM/BAR
Hamilton Oven, FDEP- Siting
Scott Osbourn, P.E., Golder Associates Inc.
Roger Zirkle, Progress Energy Florida
C. Holladay
G. Worley, SWD
J. Bunyak, NPS
D. Worley, EPA

ATTACHMENT 1

Revised Application Forms

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Progress Energy Florida**	
2. Site Name: **Hines Energy Complex**	
3. Facility Identification Number: **1050234**	
4. Facility Location...: Street Address or Other Locator: **7700 County Road 555** City: **Bartow** County: **Polk** Zip Code: **33830**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Jamie Hunter, Lead Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **PO Box 14042, MAC BB1A** City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**
3. Application Contact Telephone Numbers... Telephone: **(727) 826-4363** ext. Fax: **(727) 826-4216**
4. Application Contact Email Address:

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Power Block 4 consists of two nominal 170 MW GE Frame 7FA combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), one 190 MW steam turbine; nominal rating of 530 MW combined cycle unit, and one 20 MMBtu/hr gas-fired auxiliary boiler. See PSD Application. Fee included with Site Certification Application.

Projected or Actual Date of Commencement of Construction: January 2006
Projected Date of Completion of Construction: December 2007

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A. Power Block 2 has permit PA-92-33SA; PSD-FL-296A. Power Block 3 has permit PA-92-33SA2; PSD-FL-330.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
--	CT - 4A; Power Block 4	AC1A	
--	CT - 4B; Power Block 4	AC1A	
--	Auxiliary Boiler	AC1f	

Application Processing Fee

Check one: ☐ Attached - Amount: $__________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Roger Zirkle, Plant Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Progress Energy Florida Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4.	Owner/Authorized Representative Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Roger B Zirkle 12-3-04 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   ____________________ ______________
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

[signature]
Signature

12/3/04
Date

(seal)

SCOTT H. OSBOURN
CERTIFICATE
NO. 57557
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**** Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **414.4** North (km) **3073.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27 / 47 / 19** Longitude (DD/MM/SS) **81 / 52 / 10**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **Operation of Power Block 1 began in 1999. Power Block 1 is a nominal 470 MW combined cycle unit consisting of 2 CTs, 2 HRSGs and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. Power Blocks 2 and 3 are each a nominal 530 MW combined-cycle generating unit consisting of 2 CTs, 2 HRSGs, and 1 steam turbine. This application is for the addition of Power Block 4, an additional nominal 530 MW combined-cycle application. See PSD Application.**			

Facility Contact

1. Facility Contact Name: **Roger Zirkle, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☐ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Applicable NSPS: 40 CFR Part 60, Subpart GG, 40 CFR Part 60, Subpart Dc.** **62-212.400, F.A.C. See PSD Application.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	
Sulfur Dioxide -SO_2	**A**	
Nitrogen Oxides - NO_x	**A**	
Carbon Monoxide - CO	**A**	
Volatile Organic Compounds - VOC	**A**	
Sulfuric Acid Mist - SAM	**B**	

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig 2-1, PSD** ☐ Previously Submitted, Date:____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig 2-2, PSD** ☐ Previously Submitted, Date:____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**PSD Applic.** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID:**Fig 1-1, PSD** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☐ Attached, Document ID:____
3.	Rule Applicability Analysis: ☐ Attached, Document ID:____
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☒ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
   - ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   - ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
   - ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
   - ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.
2. Description of Emissions Unit Addressed in this Section:
   CT-4A; Power Block 4
3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**
10. Generator Nameplate Rating: **170** MW
11. Emissions Unit Comment:
    GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Dry Low NO_X combustion-natural gas firing

Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.

Water Injection – distillate oil firing

2. Control Device or Method Code(s): **25, 65, 28**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,806** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **109.2** lb/hour **71.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **82.4** lb/hour **102.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4**lb/hour **148** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Not yet determined** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	
☐ Attached, Document ID: ____	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	
☐ Attached, Document ID: ____	☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	
☒ Attached, Document ID: **See PSD Application**	☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements	
☐ Attached, Document ID: ____	☒ Not Applicable
2. Compliance Assurance Monitoring	
☐ Attached, Document ID: ____	☒ Not Applicable
3. Alternative Methods of Operation	
☐ Attached, Document ID: ____	☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)	
☐ Attached, Document ID: ____	☒ Not Applicable

5. Acid Rain Part Application
- ☐ Certificate of Representation (EPA Form No. 7610-1)
  - ☐ Copy Attached, Document ID: ____
- ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
  - ☐ Attached, Document ID: ____
  - ☐ Previously Submitted, Date: ____
- ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1] of [3]
CT-4A; Power Block 4

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   CT-4B; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: **C**	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☒ Yes ☐ No

9. Package Unit: **GE Frame 7FA**
   Manufacturer: **GE** Model Number: **Frame 7FA**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
   GE Frame 7FA combustion turbine firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**
2. Control Device or Method Code(s): **25, 65, 28**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,806** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 1,962 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Fig 2-1**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **202**°F	9. Actual Volumetric Flow Rate: **1,036,271** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 1 and 2 and revised Appendix A for PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.90**	5. Maximum Annual Rate: **15,507**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **16.3**	5. Maximum Annual Rate: **15,352**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **127.8**
10. Segment Comment: **Btu based on HHV of 127.8 MMBtu/1,000 gallons and density of 6.7 lb/gal; maximum hourly at 20°F; annual at 59°F. Aggregate fuel usage of 30,700,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x	025, 028	065	EL
CO			EL
VOC			EL
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **39.1** lb/hour **57.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **10.1** lb/hour **44.0** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): ***Gas Firing:*** **lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **39.1** lb/hour **18.9** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **109.2** lb/hour **71.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.4** lb/hour **22.1** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **109.2** lb/hour **56.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **82.4** lb/hour **102.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **72.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **82.4** lb/hour **38.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **71.4**lb/hour **148** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **32.1** lb/hour **130** tons/year
5. Method of Compliance: **EPA Method 10; based on 9 ppmvd**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **71.4** lb/hour **33** tons/year
5. Method of Compliance: **EPA Method 10; based on 20 ppmvd; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.0** lb/hour **14.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **GE, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Tables 1 and 2 and revised Appendix A for PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **12.6**tons/year
5. Method of Compliance: **EPA Method 25A; based on 1.4 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **8.0** lb/hour **3.7** tons/year
5. Method of Compliance: **EPA Method 25A; based on 3.5 ppmvw**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **10.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2004**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Tables 1 and 2 and revised Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.83** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.7** lb/hour **7.85** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION
Section [2] of [3]
CT-4B; Power Block 4

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Not yet determined** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **GE or equivalent** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_x CEM in lieu of WTF monitoring.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Fig 2-2 ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Tables 2-4/2-5 ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Section 4.0 ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: See PSD Application ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   20 MMBtu/hr Gas-Fired Auxiliary Boiler

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **Auxiliary Boiler**
   Manufacturer: **To be determined** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    20 MMBtu/hr auxiliary boiler for cold startup of GE Frame 7FA combustion turbines

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **20** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year **500**hours/year	
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Aux Boiler**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **60**feet	7. Exit Diameter: **2.5**feet
8. Exit Temperature: **332**°F	9. Actual Volumetric Flow Rate: **6,485**acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.0195**	5. Maximum Annual Rate: **9.79**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,021**
10. Segment Comment: **Based on 1,021 Btu/CF (HHV); 500 hours per year**		

Segment Description and Rate: Segment _ of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			
SO_2			
NO_x			
CO			
VOC			
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 2.0lb/hour 0.5tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.10 lb/MMBtu Reference:	7. Emissions Method Code: 2
8. Calculation of Emissions: See Tables A-29.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5 tons/year**	4. Equivalent Allowable Emissions: **2.0**lb/hour **0.5**tons/year
5. Method of Compliance: **Limitation of operation to less than 500 hours per year**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT 2

Revised Emission Tables

Table 1. Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs. SW 501F, Combined Cycle Operation
Natural Gas- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	90°F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	1,941	1,806	1,644	2,012	1,830	1,705
	Temperature	°F	203	202	201	190	190	190
	Velocity	ft/sec	72.8	67.9	62.2	63.3	59.2	55.4
PM/PM_{10}	lb/hr		10.1	10.0	9.9	8.46	7.86	7.18
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		5.43	5.05	4.60	5.63	5.12	4.77
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		17.7	16.5	15.0	18.0	16.5	15.1
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		32.1	29.7	26.8	46	42	37
	ppmvd		9.0	9.0	9.0	12.4	12.2	12.4
	ppmvd @15% O2		7.5	7.4	7.4	10.0	10.0	10.0
VOC (as methane)	lb/hr		3.09	2.88	2.65	4.65	4.35	3.75
	ppmvw		1.4	1.4	1.4	2.4	2.4	2.5
	ppmvd @15% O2		1.3	1.3	1.3	1.8	1.8	1.8
Sulfuric Acid Mist	lb/hr		0.83	0.77	0.70	0.86	0.78	0.73
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,537	1,534	1,419
	Temperature	°F	203	204	205	190	190	190
	Velocity	ft/sec	54.9	54.8	51.8	57.0	54.0	51.3
PM/PM_{10}	lb/hr		9.9	9.8	9.8	7.49	7.09	6.32
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		4.46	4.12	3.81	4.30	4.29	3.97
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		14.4	13.3	12.2	14.7	13.7	12.6
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		24.1	23.9	22.2	38	35	33
	ppmvd		9.0	9.0	9.0	11.2	11.1	10.9
	ppmvd @15% O2		6.9	7.4	7.5	10.0	10.0	10.0
VOC (as methane)	lb/hr		2.33	2.32	2.19	4.9	4.6	4.2
	ppmvw		1.4	1.4	1.4	2.8	2.8	2.8
	ppmvd @15% O2		1.2	1.3	1.3	2.3	2.3	2.3
Sulfuric Acid Mist	lb/hr		0.68	0.63	0.58	0.66	0.66	0.61
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	60	60	60
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,347	1,280	1,178
	Temperature	°F	175	178	182	190	190	190
	Velocity	ft/sec	44.4	43.5	42.1	46.0	44.0	42.3
PM/PM_{10}	lb/hr		9.7	9.7	9.6	6.08	5.84	5.48
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		3.52	3.30	3.03	3.77	3.58	3.30
	gr sulfur/100 scf		1	1	1	1	1	1
NO_x	lb/hr		11.2	10.5	9.7	12.0	11.4	10.5
	ppmvd @15% O2		2.5	2.5	2.5	2.5	2.5	2.5
CO	lb/hr		20.4	19.9	18.8	154	146	134
	ppmvd		9.0	9.0	9.0	57	57	55
	ppmvd @15% O2		7.5	7.8	8.0	50	50	50
VOC (as methane)	lb/hr		1.96	1.92	1.84	5.3	5	4.6
	ppmvw		1.4	1.4	1.4	3.7	3.7	3.6
	ppmvd @15% O2		1.3	1.3	1.4	3.0	3.0	3.0
Sulfuric Acid Mist	lb/hr		0.54	0.51	0.46	0.58	0.55	0.50
	% SO2 from CT		10	10	10	10	10	10

[a] PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table 2. Comparison of Stack, Operating, and Emission Data- GE Frame 7FA vs. SW 501F, Combined Cycle Operation
Distillate Oil- Firing

Parameter	Basis/ Units		GE Frame 7FA			SW 501F		
Stack Data	Height	ft	125	125	125	125	125	125
	Diameter	ft	18.0	18.0	18.0	19.0	19.0	19.0
Ambient Conditions	Temperature	°F	20 °F	59 °F	95 °F	20 °F	59 °F	105 °F
Operating Data	Load	%	100	100	100	100	100	100
	HIR (HHV)	MMBtu/hr	2,086	1,962	1,769	2,100	1,932	1,707
	Temperature	°F	297	295	294	270	270	270
	Velocity	ft/sec	86.2	80.0	72.7	69.4	67.0	60.0
PM/PM_{10}	lb/hr		39.1	37.8	35.7	64.8	59.6	52.5
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		109.2	102.8	92.6	105.6	97.1	85.8
	Sulfur content	%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		82.4	76.7	69.9	77.0	73.0	64.4
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		71.4	66.0	59.0	112	106	91
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.1	13.9	22.2	22.4	22.2
VOC (as methane)	lb/hr		8.01	7.45	6.79	22	21	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.8	2.8	7.9	8.1	8.1
Sulfuric Acid Mist	lb/hr		16.7	15.7	14.2	16.2	14.9	13.1
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	75	75	75	80	80	80
	HIR (HHV)	MMBtu/hr	1,594	1,473	1,361	1,644	1,524	1,364
	Temperature	°F	271	274	278	270	270	270
	Velocity	ft/sec	61.5	59.9	58.1	68.9	65.2	58.5
PM/PM_{10}	lb/hr		35.1	34.0	32.4	52.36	48.57	44.35
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		89.4	84.0	76.3	85.6	79.4	71.0
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		66.8	62.7	57.0	64.4	60.0	53.3
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		52.2	50.6	48.3	111	103	89
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		12.8	13.2	13.9	26.6	26.9	26.6
VOC (as methane)	lb/hr		5.91	5.74	5.53	21	22	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.5	2.6	2.8	9.4	9.6	9.6
Sulfuric Acid Mist	lb/hr		13.7	12.9	11.7	13.1	12.2	10.9
	% SO2 from CT		10	10	10	10	10	10
Operating Data	Load	%	50	50	50	65	65	65
	HIR (HHV)	MMBtu/hr	1,257	1,179	1,085	1,385	1,296	1,182
	Temperature	°F	256	259	268	270	270	270
	Velocity	ft/sec	50.1	49.6	48.3	63.1	59.8	55.3
PM/PM_{10}	lb/hr		31.0	30.2	29.1	43.5	40.9	37.2
	Basis [a]		Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables	Dry filterables
SO_2	lb/hr		69.1	65.5	59.6	72.1	67.5	61.5
	Sulfur content		0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
NO_x	lb/hr		51.2	48.5	44.1	54.1	50.6	46.2
	ppmvd @15% O2		10	10	10	10	10	10
CO	lb/hr		44.2	43.4	41.3	101	94	86
	ppmvd		20	20	20	30	30	30
	ppmvd @15% O2		14.2	14.7	15.4	29.3	29.5	29.2
VOC (as methane)	lb/hr		4.92	4.85	4.66	20	19	19
	ppmvw		3.5	3.5	3.5	10	10	10
	ppmvd @15% O2		2.8	2.9	3.0	10.3	10.4	10.4
Sulfuric Acid Mist	lb/hr		10.6	10.0	9.1	11.0	10.3	9.4
	% SO2 from CT		10	10	10	10	10	10

[a] PM10 includes conversion of SO2 to SO3 in the SCR to form ammonium sulfate

Table A-1. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

	CT Only		
	Turbine Inlet Temperature		
Parameter	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	193.1	173.8	154.8
Heat rate (Btu/kWh, LHV)	9,055	9,360	9,570
(Btu/kWh, HHV)	10,051	10,390	10,623
Heat Input (MMBtu/hr, LHV)- provided	1727.7	1607.1	1463.3
Heat Input (MMBtu/hr, LHV)- with margin	1,749	1,627	1,481
(MMBtu/hr, HHV)	1,941	1,806	1,644
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	3,929,264	3,650,916	3,333,093
- provided	3,882,000	3,607,000	3,293,000
Temperature (°F)	1,074	1,113	1,154
Moisture (% Vol.)	7.55	8.37	9.88
Oxygen (% Vol.)	12.75	12.57	12.34
Molecular Weight	28.48	28.38	28.22
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
Temperature (°F)	1,074	1,113	1,154
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)- calculated	2,574,253	2,461,202	2,318,987
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,749	1,627	1,481
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	83,119	77,317	70,399
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,900,799	1,768,116	1,609,909
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
HRSG Stack Temperature (^{o}F)	203	202	201
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)	1,112,097	1,036,271	949,721
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	72.8	67.9	62.2

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Particulate from CT and SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	5.4	5.1	4.6
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1.12	1.04	0.95
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	10.1	10.0	9.9
(lb/mmBtu, HHV)	0.0052	0.0056	0.0061
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,900,799	1,768,116	1,609,909
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	5.4	5.1	4.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	63.6	59.4	53.8
(lb/hr)- provided	63.0	59.0	53.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	17.7	16.5	15.0
(lb/MMBtu)	0.0091	0.0091	0.0091
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	9	9	9
Basis, ppmvd @ 15% O2 - calculated	7.47	7.39	7.37
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	32.1	29.7	26.8
(lb/hr)- provided	32.0	29.0	26.0

Table A-2. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.26	1.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%) wet	12.75	12.57	12.34
CT Flow (acfm)	2,574,253	2,461,202	2,318,987
CT Exhaust Temperature (°F)	1,074	1,113	1,154
HRSG Emission rate (lb/hr)	3.09	2.88	2.65
(lb/hr)- provided	3.00	2.80	2.60
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	5.4	5.1	4.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.83	0.77	0.70
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants forthe Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	2.33E-09	2.17E-09	1.97E-09
(TPY)	1.02E-08	9.49E-09	8.64E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-06	1.44E-06	1.32E-06
(TPY)	6.80E-06	6.33E-06	5.76E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,941	1,806	1,644
Total	1,941	1,806	1,644
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.55E-03	1.44E-03	1.32E-03
(TPY)	6.80E-03	6.33E-03	5.76E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,941	1,806	1,644
Emission Rate (lb/hr)	1.94E-02	1.81E-02	1.64E-02
(TPY)	8.50E-02	7.91E-02	7.20E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-5. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	144.8	132.2	116.1
Heat rate (Btu/kWh, LHV)	9,915	10,040	10,560
(Btu/kWh, HHV)	11,006	11,144	11,722
Heat Input (MMBtu/hr, LHV)- provided	1,419	1,311	1,211
Heat Input (MMBtu/hr, LHV)- with margin	1,436	1,327	1,226
(MMBtu/hr, HHV)	1,594	1,473	1,361
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,956,564	2,941,381	2,762,226
- provided	2,921,000	2,906,000	2,729,000
Temperature (°F)	1,200	1,159	1,190
Moisture (% Vol.)	8.13	8.26	9.8
Oxygen (% Vol.)	12.11	12.60	12.43
Molecular Weight	28.44	28.41	28.22
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
Temperature (°F)	1,200	1,159	1,190
Molecular weight	28.44	28.41	28.22
Volume flow (acfm)- calculated	2,099,089	2,039,302	1,964,313
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,436	1,327	1,226
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	68,258	63,081	58,270
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,560,950	1,442,570	1,332,551
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
HRSG Stack Temperature (°F)	203	204	205
Molecular weight	28.44	28.41	28.22
CT volume flow (acfm)	837,992	836,001	791,320
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	54.9	54.8	51.8

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	4.5	4.1	3.8
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.90	0.83	0.77
Total CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total HRSG emission rate (lb/hr) [a + b]	9.9	9.8	9.8
(lb/mmBtu, HHV)	0.0062	0.0067	0.0072
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,560,950	1,442,570	1,332,551
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	4.5	4.1	3.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flc 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr)	51.7	47.8	44.1
(lb/hr)- provided	51.0	47.0	44.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	14.4	13.3	12.2
(lb/MMBtu)	0.0090	0.0090	0.0090
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	9	9	9
Basis, ppmvd @ 15% O2 - calculated	6.88	7.41	7.46
Moisture (%)	8.13	8.26	9.80
Oxygen (%)	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	24.1	23.9	22.2
(lb/hr)- provided	24.0	24.0	22.0

Table A-6. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	CT Only Turbine Inlet Temperature 20 °F	 59 °F	 95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.2	1.3	1.3
Moisture (%)	8.13	8.26	9.80
Oxygen (%) wet	12.11	12.60	12.43
CT Flow (acfm)	2,099,089	2,039,302	1,964,313
CT Exhaust Temperature (°F)	1,200	1,159	1,190
HRSG Emission rate (lb/hr)	2.33	2.32	2.19
(lb/hr)- provided	2.4	2.2	2.2
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	4.5	4.1	3.8
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.68	0.63	0.58
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.91E-09	1.77E-09	1.63E-09
(TPY)	8.38E-09	7.74E-09	7.15E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-06	1.18E-06	1.09E-06
(TPY)	5.59E-06	5.16E-06	4.77E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,594	1,473	1,361
Total	1,594	1,473	1,361
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.28E-03	1.18E-03	1.09E-03
(TPY)	5.59E-03	5.16E-03	4.77E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,594	1,473	1,361
Emission Rate (lb/hr)	1.59E-02	1.47E-02	1.36E-02
(TPY)	6.98E-02	6.45E-02	5.96E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-9. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.6	88.2	77.4
Heat rate (Btu/kWh, LHV)	11,730	12,050	12,620
(Btu/kWh, HHV)	13,020	13,376	14,008
Heat Input (MMBtu/hr, LHV)- provided	1,119	1,050	965
Heat Input (MMBtu/hr, LHV)- with margin	1,133	1,062	977
(MMBtu/hr, HHV)	1,257	1,179	1,085
Evaporative Cooler status/efficiency (%)	Off	Off	Off
Relative Humidity (%)	80	60	50
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,353	23,353	23,353
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,498,048	2,433,269	2,325,978
- provided	2,468,000	2,404,000	2,298,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	7.54	7.96	9.37
Oxygen (% Vol.)	12.77	12.94	12.92
Molecular Weight	28.48	28.42	28.25
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.48	28.42	28.25
Volume flow (acfm)- calculated	1,770,983	1,728,651	1,662,592
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,133	1,062	977
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	53,834	50,496	46,445
Heat content (Btu/cf, LHV)- assumed	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,231,113	1,154,760	1,062,124
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
HRSG Stack Temperature (^{o}F)	175	178	182
Molecular weight	28.48	28.42	28.25
CT volume flow (acfm)	677,774	663,865	643,203
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	44.4	43.5	42.1

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	3.5	3.3	3.0
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	0.71	0.67	0.61
CT emission rate (lb/hr) [a]	9.0	9.0	9.0
Total emission rate (lb/hr) [a + b]	9.7	9.7	9.6
(lb/mmBtu, HHV)	0.0077	0.0082	0.0089
Sulfur Dioxide			
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,231,113	1,154,760	1,062,124
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
HRSG emission rate (lb/hr)	3.5	3.3	3.0
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flov 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	9	9	9
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	40.3	37.8	34.8
(lb/hr)- provided	40.0	37.0	34.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	2.5	2.5	2.5
(lb/hr)	11.2	10.5	9.7
(lb/MMBtu)	0.0089	0.0089	0.0089
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	9	9	9
Basis, ppmvd @ 15% O2 - calculated	7.49	7.76	7.99
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	20.4	19.9	18.8
(lb/hr)- provided	20	20	19

Table A-10. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	1.4	1.4	1.4
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.4
Moisture (%)	7.54	7.96	9.37
Oxygen (%) wet	12.77	12.94	12.92
CT Flow (acfm)	1,770,983	1,728,651	1,662,592
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	1.96	1.92	1.84
(lb/hr)- provided	2.00	1.80	1.80
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	3.5	3.3	3.0
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	0.54	0.51	0.46
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.51E-09	1.42E-09	1.30E-09
(TPY)	6.61E-09	6.20E-09	5.70E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-06	9.43E-07	8.68E-07
(TPY)	4.41E-06	4.13E-06	3.80E-06

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,257	1,179	1,085
Total	1,257	1,179	1,085
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.01E-03	9.43E-04	8.68E-04
(TPY)	4.41E-03	4.13E-03	3.80E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,257	1,179	1,085
Emission Rate (lb/hr)	1.26E-02	1.18E-02	1.08E-02
(TPY)	5.51E-02	5.17E-02	4.75E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-13. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	193.5	181.5	158.9
Heat rate (Btu/kWh, LHV)	10,050	10,080	10,380
(Btu/kWh, HHV)	10,778	10,810	11,132
Heat Input (MMBtu/hr, LHV)- provided	1,945	1,830	1,649
Heat Input (MMBtu/hr, LHV)- with margin	1,945	1,830	1,649
(MMBtu/hr, HHV)	2,086	1,962	1,769
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
Fuel density (lb/gal)	6.69	6.69	6.69
CT Exhaust Flow	127808.542		
Mass Flow (lb/hr)- with margin	4,055,000	3,766,000	3,407,000
- provided	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Moisture (% Vol.)	10.87	11.46	13.07
Oxygen (% Vol.)	11.24	11.11	10.77
Molecular Weight	28.36	28.30	28.12
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,055,000	3,766,000	3,407,000
Temperature (°F)	1,053	1,093	1,143
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)- calculated	2,631,766	2,514,188	2,362,720
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,945	1,830	1,649
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	109,234	102,764	92,647
(gal/hr)	16,318	15,352	13,840
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	4,055,000	3,766,000	3,407,000
HRSG Stack Temperature (°F)	297	295	294
Molecular weight	28.36	28.30	28.12
Volume flow (acfm)	1,316,753	1,221,963	1,110,611
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	86.2	80.0	72.7

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	109.2	102.8	92.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	22.08	20.77	18.73
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG emission rate (lb/hr) [a + b]	39.1	37.8	35.7
(lb/mmBtu, HHV)	0.0187	0.0193	0.0202
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	109,234	102,764	92,647
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	109.2	102.8	92.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (ac 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	345.9	322.3	293.5
(lb/hr)- provided	345.0	323.0	293.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10
(lb/hr)	82.4	76.7	69.9
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	20	20	20
Basis, ppmvd @ 15% O2 - calculated	14.24	14.13	13.86
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	71.4	66.0	59.0
(lb/hr)- provided	71.0	66.0	59.0

Table A-14. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.8	2.8	2.8
Moisture (%)	10.87	11.46	13.07
Oxygen (%) wet	11.24	11.11	10.77
CT Flow (acfm)	2,631,766	2,514,188	2,362,720
CT Exhaust Temperature (°F)	1,053	1,093	1,143
HRSG Emission rate (lb/hr)	8.01	7.45	6.79
(lb/hr)- provided	8.00	7.50	7.00
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	109.2	102.8	92.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	16.73	15.74	14.19
(lb/hr)- provided	10.6	9.9	9.0
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0272	0.0256	0.0231

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.93E-07	7.46E-07	6.72E-07
(TPY)	3.96E-07	3.73E-07	3.36E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.90E-04	6.49E-04	5.86E-04
(TPY)	3.45E-04	3.25E-04	2.93E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.79E-02	6.38E-02	5.76E-02
(TPY)	3.39E-02	3.19E-02	2.88E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.49E-01	4.23E-01	3.81E-01
(TPY)	2.25E-01	2.11E-01	1.91E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	2,086	2,086	2,086
Emission Rate (lb/hr)	1.31E-03	1.31E-03	1.31E-03
(TPY)	6.53E-04	6.53E-04	6.53E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	2,086	1,962	1,769
	2,086	1,962	1,769
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.65E-02	1.55E-02	1.40E-02
(TPY)	8.25E-03	7.76E-03	7.00E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	2.29E-03	2.16E-03	1.95E-03
(TPY)	1.15E-03	1.08E-03	9.73E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	6.76E-03	6.36E-03	5.73E-03
(TPY)	3.38E-03	3.18E-03	2.87E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.41E-02	1.33E-02	1.20E-02
(TPY)	7.05E-03	6.63E-03	5.98E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	7.72E-02	7.26E-02	6.54E-02
(TPY)	3.86E-02	3.63E-02	3.27E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	9.01E-01	8.48E-01	7.64E-01
(TPY)	4.50E-01	4.24E-01	3.82E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	1.80E-01	1.69E-01	1.53E-01
(TPY)	9.00E-02	8.47E-02	7.63E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	0.625683712	0.588619505	0.530674508
(TPY)	3.13E-01	2.94E-01	2.65E-01

Table A-16. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.80E-02	4.51E-02	4.07E-02
(TPY)	2.40E-02	2.26E-02	2.03E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	2,086	1,962	1,769
Emission Rate (lb/hr)	4.94E-01	4.65E-01	4.19E-01
(TPY)	2.47E-01	2.33E-01	2.10E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-17. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	145.1	135.5	119.2
Heat rate (Btu/kWh, LHV)	10,970	11,030	11,400
(Btu/kWh, HHV)	11,765	11,829	12,226
Heat Input (MMBtu/hr, LHV)- provided	1,592	1,495	1,359
Heat Input (MMBtu/hr, LHV)- with margin	1,592	1,495	1,359
(MMBtu/hr, HHV)	1,707	1,603	1,457
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,991,000	2,898,000	2,783,000
- provided	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Moisture (% Vol.)	11.72	11.85	12.65
Oxygen (% Vol.)	10.34	10.57	10.86
Molecular Weight	28.32	28.29	28.16
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
Temperature (°F)	1,196	1,200	1,200
Molecular weight	28.32	28.29	28.16
Volume flow (acfm)- calculated	2,127,478	2,068,807	1,995,375
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,592	1,495	1,359
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	89,406	83,952	76,330
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
HRSG Stack Temperature (°F)	271	274	278
Molecular weight	28.32	28.29	28.16
CT volume flow (acfm)	938,994	914,512	886,499
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	61.5	59.9	58.1

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	89.4	84.0	76.3
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	18.07	16.97	15.43
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	35.1	34.0	32.4
(lb/mmBtu, HHV)	0.0203	0.0210	0.0220
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	89,406	83,952	76,330
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	89.4	84.0	76.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
CT Emission rate (lb/hr)	280.5	263.5	239.3
(lb/hr)- provided	280.0	263.0	239.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	66.8	62.7	57.0
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	20	20	20
Basis, ppmvd @ 15% O2 - calculated	12.84	13.24	13.94
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	52.2	50.6	48.3
(lb/hr)- provided	52.0	51.0	48.0

Table A-18. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.5	2.6	2.8
Moisture (%)	11.72	11.85	12.65
Oxygen (%) wet	10.34	10.57	10.86
CT Flow (acfm)	2,127,478	2,068,807	1,995,375
CT Exhaust Temperature (°F)	1,196	1,200	1,200
HRSG Emission rate (lb/hr)	5.91	5.74	5.53
(lb/hr)- provided	6.00	5.50	5.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	89.4	84.0	76.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	13.69	12.86	11.69
(lb/hr)- provided	8.70	8.10	7.40
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0223	0.0209	0.0190

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.49E-07	6.09E-07	5.54E-07
(TPY)	3.24E-07	3.05E-07	2.77E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.65E-04	5.31E-04	4.82E-04
(TPY)	2.83E-04	2.65E-04	2.41E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.55E-02	5.22E-02	4.74E-02
(TPY)	2.78E-02	2.61E-02	2.37E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.68E-01	3.45E-01	3.14E-01
(TPY)	1.84E-01	1.73E-01	1.57E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,707	1,707	1,707
Emission Rate (lb/hr)	1.07E-03	1.07E-03	1.07E-03
(TPY)	5.34E-04	5.34E-04	5.34E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,707	1,603	1,457
	1,707	1,603	1,457
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.35E-02	1.27E-02	1.15E-02
(TPY)	6.75E-03	6.34E-03	5.76E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.88E-03	1.76E-03	1.60E-03
(TPY)	9.39E-04	8.82E-04	8.02E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	5.53E-03	5.19E-03	4.72E-03
(TPY)	2.77E-03	2.60E-03	2.36E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.15E-02	1.08E-02	9.85E-03
(TPY)	5.77E-03	5.42E-03	4.93E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	6.32E-02	5.93E-02	5.39E-02
(TPY)	3.16E-02	2.97E-02	2.70E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	7.37E-01	6.92E-01	6.30E-01
(TPY)	3.69E-01	3.46E-01	3.15E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	1.47E-01	1.38E-01	1.26E-01
(TPY)	7.37E-02	6.92E-02	6.29E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	0.51211023	0.480869479	0.437209645
(TPY)	2.56E-01	2.40E-01	2.19E-01

Table A-20. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	3.93E-02	3.69E-02	3.35E-02
(TPY)	1.96E-02	1.84E-02	1.68E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,707	1,603	1,457
Emission Rate (lb/hr)	4.05E-01	3.80E-01	3.45E-01
(TPY)	2.02E-01	1.90E-01	1.73E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-21. Design Information and Stack Parameters for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Combustion Turbine Performance			
Power output (MW)	96.7	90.3	79.4
Heat rate (Btu/kWh, LHV)	12,730	12,920	13,370
(Btu/kWh, HHV)	13,652	13,856	14,339
Heat Input (MMBtu/hr, LHV)- provided	1,231	1,167	1,062
Heat Input (MMBtu/hr, LHV)- with margin	1,231	1,167	1,062
(MMBtu/hr, HHV)	1,320	1,251	1,139
Relative Humidity (%)	60	60	60
Fuel heating value (Btu/lb, LHV)	17,803	17,803	17,803
(Btu/lb, HHV)	19,093	19,093	19,093
(HHV/LHV)	1.072	1.072	1.072
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin	2,499,000	2,457,000	2,353,000
- provided	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	10.19	10.38	11.37
Oxygen (% Vol.)	11.30	11.54	11.73
Molecular Weight	28.44	28.40	28.26
CT Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.44	28.40	28.26
Volume flow (acfm)- calculated	1,774,396	1,747,217	1,681,491
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,231	1,167	1,062
Heat content (Btu/lb, LHV)	17,803	17,803	17,803
Fuel usage (lb/hr)- calculated	69,146	65,534	59,630
HRSG Stack			
HRSG - Stack Height (ft)	125	125	125
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
HRSG Stack Temperature (°F)	256	259	268
Molecular weight	28.44	28.40	28.26
CT volume flow (acfm)	765,021	756,777	737,121
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	50.1	49.6	48.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Particulate from CTand SCR			
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only			
a. PM_{10} (front half)			
CT (lb/hr)- provided	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	69.1	65.5	59.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	13.98	13.25	12.05
CT emission rate (lb/hr) [a]	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	31.0	30.2	29.1
(lb/mmBtu, HHV)	0.0235	0.0242	0.0255
Sulfur Dioxide			
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100			
Fuel oil Sulfur Content	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	69,146	65,534	59,630
lb SO2 / lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	69.1	65.5	59.6
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	42	42	42
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	215.0	203.7	185.2
(lb/hr)- provided	215.0	203.0	185.0
HRSG Stack emission rate (ppmvd @ 15% O_2)	10	10	10.0
(lb/hr)	51.2	48.5	44.1
Carbon Monoxide			
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd	20	20	20
Basis, ppmvd @ 15% O2 - calculated	14.19	14.71	15.39
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	44.2	43.4	41.3
(lb/hr)- provided	44.0	43.0	41.0

Table A-22. Maximum Emissions for Criteria Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Volatile Organic Compounds			
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvw	3.5	3.5	3.5
Basis, ppmvd @ 15% O2 - calculated	2.8	2.9	3.0
Moisture (%)	10.19	10.38	11.37
Oxygen (%) wet	11.30	11.54	11.73
CT Flow (acfm)	1,774,396	1,747,217	1,681,491
CT Exhaust Temperature (°F)	1,200	1,200	1,200
HRSG Emission rate (lb/hr)	4.92	4.85	4.66
(lb/hr)- provided	5.00	5.00	4.50
Sulfuric Acid Mist			
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
CT SO_2 emission rate (lb/hr) - provided	69.1	65.5	59.6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10
MW H2SO4 /MW SO2 (98/64)	1.53	1.53	1.53
HRSG Emission rate (lb/hr)	10.59	10.03	9.13
(lb/hr)- provided	6.70	6.30	5.80
Lead			
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Emission Rate Basis (lb/10^{12} Btu)	14	14	14
Emission rate (lb/hr)	0.0172	0.0163	0.0149

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 2004 - CT Performance Data; Golder Associates, 2004

Table A-23. *Maximum Emissions for Other Regulated PSD Pollutants for the Hines Energy Complex, Power Block 4*
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.02E-07	4.75E-07	4.33E-07
(TPY)	2.51E-07	2.38E-07	2.16E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.37E-04	4.14E-04	3.77E-04
(TPY)	2.18E-04	2.07E-04	1.88E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.30E-02	4.07E-02	3.70E-02
(TPY)	2.15E-02	2.04E-02	1.85E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [c], lb/10^{12} Btu	2.15E+02	2.15E+02	2.15E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	2.84E-01	2.70E-01	2.45E-01
(TPY)	1.42E-01	1.35E-01	1.23E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,320	1,320	1,320
Emission Rate (lb/hr)	8.26E-04	8.26E-04	8.26E-04
(TPY)	4.13E-04	4.13E-04	4.13E-04

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Heat Input Rate (MMBtu/hr), HHV- CT	1,320	1,251	1,139
	1,320	1,251	1,139
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.04E-02	9.90E-03	9.01E-03
(TPY)	5.22E-03	4.95E-03	4.50E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.45E-03	1.38E-03	1.25E-03
(TPY)	7.26E-04	6.88E-04	6.26E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.28E-03	4.05E-03	3.69E-03
(TPY)	2.14E-03	2.03E-03	1.84E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	8.92E-03	8.46E-03	7.70E-03
(TPY)	4.46E-03	4.23E-03	3.85E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	4.88E-02	4.63E-02	4.21E-02
(TPY)	2.44E-02	2.31E-02	2.11E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	5.70E-01	5.41E-01	4.92E-01
(TPY)	2.85E-01	2.70E-01	2.46E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	1.14E-01	1.08E-01	9.83E-02
(TPY)	5.70E-02	5.40E-02	4.91E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	0.396059366	0.375371619	0.341556965
(TPY)	1.98E-01	1.88E-01	1.71E-01

Table A-24. Maximum Emissions for Hazardous Air Pollutants for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.04E-02	2.88E-02	2.62E-02
(TPY)	1.52E-02	1.44E-02	1.31E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis [a], lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,320	1,251	1,139
Emission Rate (lb/hr)	3.13E-01	2.97E-01	2.70E-01
(TPY)	1.56E-01	1.48E-01	1.35E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA,1996 (AP-42,Table 3.1-4)

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

Pollutant	Load:	Maximum Hourly Emissions (lb/hr)[a] Natural Gas 100%	Natural Gas 50%	Distillate Oil 100%	Maximum Annual Emissions (tons/year)[b] Case A	Case B	Case C	Case D	Auxiliary Boiler	TOTAL	PSD Significant Emission Rates
One Combustion Turbine- Combined Cycle											
SO_2		5.1	3.3	102.8	22.1	19.5	71.0	68.4	0.014	71.0	40
PM/PM_{10}		10.0	9.7	37.8	44.0	43.4	57.8	57.3	0.025	57.9	25/15
NO_x		16.5	11	77	72.3	63.3	102.4	93.4	0.50	103	40
CO		29.7	19.9	66.0	130.1	115.3	148.2	133.5	0.25	148	100
VOC (as methane)		2.9	1.9	7.5	12.6	11.2	14.9	13.5	0.25	15.2	40
Sulfuric Acid Mist		0.77	0.5	15.7	3.4	3.0	10.9	10.5	0.002	10.9	7
Lead		0.00E+00	0.00E+00	2.56E-02	0.00E+00	0.00E+00	1.28E-02	1.28E-02	0.00E+00	1.28E-02	0.6
Mercury		1.44E-06	9.43E-07	1.31E-03	6.33E-06	5.58E-06	6.58E-04	6.58E-04	Neg.	6.58E-04	0.1
MWC Organics (as 2,3,7,8-TCDD)		2.17E-09	1.42E-09	7.46E-07	9.49E-09	8.36E-09	3.81E-07	3.80E-07	Neg.	3.81E-07	3.50E-06
MWC Metals (Be & Cd)		0.00E+00	0.00E+00	7.01E-03	0.00E+00	0.00E+00	3.50E-03	3.50E-03	0.00E+00	3.50E-03	15
MWC Acid Gases (HCl)		0.00E+00	0.00E+00	0.42	0.00E+00	0.00E+00	2.11E-01	2.11E-01	0.00E+00	2.11E-01	40
Total HAPs		0.41	0.30	2.54	1.79	1.63	2.86	2.70	0.40	3.26	25
Two Combustion Turbines- Combined Cycle											
SO_2		10.1	6.6	205.5	44.3	39.0	142.0	136.7	0.014	142	40
PM/PM_{10}		20	19	76	88	87	116	115	0.025	116	25/15
NO_x		33	21	153	145	127	205	187	0.50	205	40
CO		59	40	132	260	231	296	267	0.25	297	100
VOC (as methane)		5.8	3.8	14.9	25.2	22.3	29.8	26.9	0.25	30.1	40
Sulfuric Acid Mist		1.5	1.01	31.47	6.78	5.97	21.74	20.93	0.002	21.7	7
Lead		0.00E+00	0.00E+00	5.12E-02	0.00E+00	0.00E+00	2.56E-02	2.56E-02	0.00E+00	2.56E-02	0.6
Mercury		2.89E-06	1.89E-06	2.61E-03	1.27E-05	1.12E-05	1.32E-03	1.32E-03	Neg.	1.32E-03	0.1
MWC Organics (as 2,3,7,8-TCDD)		4.33E-09	2.83E-09	1.49E-06	1.90E-08	1.67E-08	7.62E-07	7.60E-07	Neg.	7.62E-07	3.50E-06
MWC Metals (Be & Cd)		0.00E+00	0.00E+00	1.40E-02	0.00E+00	0.00E+00	7.01E-03	7.01E-03	0.00E+00	7.01E-03	15
MWC Acid Gases (HCL)		0.0	0.00	0.85	0.00	0.00	4.23E-01	4.23E-01	0.00E+00	4.23E-01	40
Total HAPs		0.8	0.60	5.09	3.59	3.26	5.72	5.40	0.4	6.12	25

[a] Based on 59 °F compressor inlet air temperature

[b] Maximim emission cases:

Operation	Number of Hours for Operation Case A	Case B	Case C	Case D
100 % Load- Gas	8,760	5,760	7,760	4,760
50% Load- Gas	0	3000	0	3,000
100 % Load- Oil	0	0	1,000	1,000
Total hours	8,760	8,760	8,760	8,760

Table A-26. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 100% Load

Parameter	CT Only Turbine Inlet Temperature and Load		
	100% 20 °F	100% 59 °F	100% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Turbine Flow (acfm)	2,574,253	2,461,202	2,318,987
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	0.420	0.392	0.355
Heat Input (MMBtu/hr, HHV)	1941	1806	1644
CT Emission rate (lb/10^{12} Btu)	216.1	216.9	215.9

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-27. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	CT Only Turbine Inlet Temperature and Load		
	50% 20 °F	50% 59 °F	50% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Turbine Flow (acfm)	1,770,983	1,728,651	1,662,592
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr)	0.266	0.249	0.229
Heat Input (MMBtu/hr, HHV)	1,257	1,179	1,085
CT/DB Emission rate (lb/10^{12} Btu)	211.6	211.5	211.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Golder Associates, 2004

Table A-28. Formaldehyde Emissions for the Hines Energy Complex, Power Block 4
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 95 °F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Turbine Flow (acfm)	2,631,766	2,514,188	2,362,720
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	0.489	0.455	0.415
Heat Input (MMBtu/hr, HHV)	2,086	1,962	1,769
CT Emission rate (lb/10^{12} Btu)	234.4	232.1	234.5

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

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Table A-29. Auxiliary Boiler Emissions for the Hines Energy Complex, Power Block 4

Parameter	Value		
Conditions			
Ambient Temperature (^oF)	72		
Load Condition (%)	100		
Hear Input Rate (MMBtu/hr), maximum	20		
Fuel Usage			
Heat content (Btu/cf, HHV)	1,021		
Fuel usage (cf/hr)- calculated	19,585		
Hours of Operation	500		
Sulfur content (gr/100 scf)	1		
Emissions [a]	lb/MMBtu	lb/hr	TPY
SO_2	0.0028	0.056	0.014
PM/PM_{10}	0.005	0.10	0.025
NO_x	0.10	2.00	0.5
CO	0.049	0.98	0.25
VOC (as methane)	0.049	0.98	0.25
Sulfuric Acid Mist [c]	0.00043	0.0086	0.0021
Lead	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.
Benzene [b]	0.002	0.04	0.01
Formaldehyde [b]	0.075	1.50	0.38
Toluene [b]	0.003	0.07	0.02
Stack Parameters			
Height (ft)	60		
Diameter (ft)	2.5		
Exit gas temperature (^oF)	332		
Exit gas flow rate (acfm)	6,485		
Exit gas velocity (ft/s)	22.0		

[a] Emissions based on maunufacturer's data (Black & Veatch, 1992).

[a] Emissions based on natural gas combustion from AP-42, Compilation of Air Pollutant Emission Factors for Stationary Sources, Chapter 1.4 (U.S. EPA, 1998).

[c] Based on 10 peercent of SO2 emissions.

ATTACHMENT 3

Revised BACT Tables

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$968,481	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$127,782	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$58,109	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$48,424	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,297,301	$16,492,225	
Direct Installation Costs			
Foundation and supports	$103,784	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$181,622	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$51,892	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$25,946	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$12,973	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$12,973	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$409,190	$4,967,668	
Total Capital Costs (TCC)	$1,706,491	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$129,730	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$64,865	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$129,730	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$25,946	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$12,973	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$38,919	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$452,163	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,158,654	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3b. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,065,329	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$127,782	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$63,920	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$53,266	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,404,802	$16,492,225	
Direct Installation Costs			
Foundation and supports	$112,384	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$196,672	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$56,192	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$28,096	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$14,048	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$14,048	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$441,441	$4,967,668	
Total Capital Costs (TCC)	$1,846,243	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$140,480	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$70,240	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$140,480	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$28,096	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$14,048	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$42,144	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$485,489	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,331,731	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$114,985	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$19,384	$29,076	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$176,540	$264,810	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$10,423	$10,108	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$357,860	$347,051	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$221,431	$666,860	0.20 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$249,463	$1,476,245	
Indirect Annual Costs			
Overhead	81,908	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	21,587	265,725	1% of Total Capital Costs
Insurance	21,587	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	237,020	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$362,101	$3,474,942	
Total Annualized Costs	$969,425	$5,298,237	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per ton of NO_x Removed
Incremental Cost Effectiveness (9 to 3.5)	$3,672	$20,070	per incremental ton of NO_x Removed
	263.99	263.99	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4b. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$31,200	$62,400	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$4,680	$9,360	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$126,139	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$25,728	$38,592	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times $
Catalyst Cost	$234,317	$351,475	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$13,112	$13,855	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$450,176	$475,682	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCOI
MW Loss and Heat Rate Penalty	$265,718	$666,860	0.24 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90%
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$293,750	$1,476,245	
Indirect Annual Costs			
Overhead	97,211	43,056	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,317	265,725	1% of Total Capital Costs
Insurance	23,317	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	256,024	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sur
Total Indirect Annual Costs (TIAC)	$399,870	$3,492,164	
Total Annualized Costs	$1,143,795	$5,444,091	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (9 to 2.5)	$3,950	$18,799	per ton of NO_x Removed
Incremental Cost Effectiveness (3.5 to 2.5)	$6,809	$5,696	per incremental ton of NO_x Removed
	289.60	289.60	tons NOx removed /year; 2.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,158,654	$26,572,482
Annualized Costs	included	$969,425	$5,298,237
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$3,672	$20,070
Environmental Impact [b]			
Total NOx (TPY)	392	128.0	128.0
NOx Reduction (TPY)	NA	264	264
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.2	0
Secondary Emissions (TPY)	0	4.4	40.4
Net Emission Reduction (TPY)	NA	-134	-224
Addition Greenhouse Gas (as CO2; tons/year)	0	2,437	22,404
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	3,872,631	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,171,831	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	323	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	38,483	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	38	354
Energy Use (percent of combustion turbine output)	0	0.24%	2.24%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5b. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (2.5 ppmvd corrected)	DLN with SCONOx™ (2.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrat	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,331,731	$26,572,482
Annualized Costs	included	$1,143,795	$5,444,091
Cost Effectiveness (per ton of Nox removed)			
Incremental from 2.5 ppm	NA	$6,809	$5,696
Environmental Impact [b]			
Total NOx (TPY)	392	102.4	102.4
NOx Reduction (TPY)	NA	290	290
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	12.3	0
Secondary Emissions (TPY)	0	5.1	40.4
Net Emission Reduction (TPY)	NA	-159	-249
Additional Greenhouse Gas (as CO_2; tons/year)	0	2,837	22,404
Energy Impacts [c]			
Energy Use (kWh/yr)	0	4,506,997	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	3,806,197	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	24,643,482
Energy Use (Equivalent Residential Customers/year)	0	376	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	44,787	353,740
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	45	354
Energy Use (percent of combustion turbine output)	0	0.28%	2.24%

[a] See Tables B-3b, B-4b, and B-5b for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.34 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

Pollutants	Incremental Emissions (tons/year) of SCR Primary	Secondary	Total	Incremental Emissions (tons/year) of SCONOx™ Primary	Secondary	Total
Particulate	12.17	0.14	12.31		1.28	1.28
Sulfur Dioxide		0.05	0.05		0.48	0.48
Nitrogen Oxides	-263.99	2.57	-261.43	-263.99	23.58	-240.41
Carbon Monoxide		1.54	1.54		14.15	14.15
Volatile Organic Compounds		0.10	0.10		0.93	0.93
Ammonia	113.04					
Total:	-138.78	4.40	-134.38	-263.99	40.42	-223.57
Carbon Dioxide (all energy requirements)		2,437.28	2,437.28		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	38,483	353,740 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6b. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) (2.5 ppm)

	Incremental Emissions (tons/year) of SCR					
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	12.17	0.16	12.33		1.28	1.28
Sulfur Dioxide		0.06	0.06		0.48	0.48
Nitrogen Oxides	-289.60	2.99	-286.62	-289.60	23.58	-266.02
Carbon Monoxide		1.79	1.79		14.15	14.15
Volatile Organic Compounds		0.12	0.12		0.93	0.93
Ammonia	113.04					
Total:	-164.39	5.12	-159.27	-289.60	40.42	-249.18
Carbon Dioxide (all energy requirements)		2,836.53	2,836.53		22,403.56	22,403.56

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	44,787	353,740 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment Minus Catalyst	$99,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$77,300	10% of SCR Associated Equipment
Sales Tax	$5,940	6% of SCR Associated Equipment/Catalyst
Freight	$4,950	5% of SCR Associated Equipment/Catalyst
CO Catalyst	$674,000	Vendor Quote
Sales Tax	$40,440	6% of SCR Associated Equipment/Catalyst
Freight	$33,700	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$979,835	
Direct Installation Costs		
Foundation and supports	$78,387	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$137,177	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$39,193	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,597	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,798	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$298,951	
Total Capital Costs	$1,278,786	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$48,992	5% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$97,984	10% of Total Direct Capital Costs; OAQPS Cost Control Manual
Start-up	$19,597	2% of Total Direct Capital Costs; OAQPS Cost Control Manual
Performance Tests	$9,798	1% of Total Direct Capital Costs; OAQPS Cost Control Manual
Contingencies	$29,395	3% of Total Direct Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$303,749	
Total Direct, Indirect and Capital Costs (TDICC)	$1,582,535	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst, GE 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Annualized Catalyst Replacement (Catalyst+Tax+Shipping)	$285,041	38.10% Capital Recovery Factor of 7% over 3 yrs times sum of TDICC
Contingency	$8,767	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$300,984	
Energy Costs		
Heat Rate Penalty	$349,051	0.2% of MW output, $0.05/kW; EPA, 1993 (Page 6-20) and $6/mmBtu added fuel costs (DOE,2004)
Total Energy Costs (TDEC)	$349,051	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$15,825	1% of Total Capital Costs
Insurance	$15,825	1% of Total Capital Costs
Annualized Total Direct Capital Minus Catalyst	$91,617	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$127,573	
Total Annualized Costs	$777,608	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$6,517	per ton of CO Removed
	$7,510	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,582,535
Annualized Costs	included	$777,608
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$6,517
Environmental Impact [b]		
Total CO (TPY)	148	29
CO Reduction (TPY)	NA	119
Net Pollutant Reduction	NA	104
Additional Greenhouse Gas (CO2; tons/yr)	--	2,004
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,184,085
Energy Use (Equivalent Residential Customers/year)	0	265
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,641
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	32

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year. Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

	Incremental Emissions (tons/year) of SCR		
Pollutants	Primary	Secondary	Total
Particulate	12.17	0.11	12.29
Sulfur Dioxide		0.04	0.04
Nitrogen Oxides	0.00	2.11	2.11
Carbon Monoxide	-119.3	1.27	-118.1
Volatile Organic Compounds		0.08	0.08
Total:	-107.2	3.62	-103.5
Carbon Dioxide (additional from gas firing)		2,003.9	2,003.9

Basis:

Lost Energy (mmBtu/year)	31,641
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.	
Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

ATTACHMENT 4

GE Formaldehyde Data

GE Energy

Jeanne M. Beres
Manager – Environmental & Acoustic Engineering
Global Power Plont Systems

1 River Road, Bldg. 2-506
Schenectody, NY 12345
USA

T 518 385 0554
F 518 381 2706
jeanne.beres@ge.com

Kevin Murray
Manager, Project Engineering
Progress Energy, Inc.
Plant Construction Department
410 South Wilmington Street – PEB 9A
Raleigh, NC 27601
kevin.murray@pgnmail.com

October 6, 2004

Dear Mr. Murray:

In response to increased requests for formaldehyde emissions for GE combustion turbines in light of the promulgation of the combustion turbines MACT standard (40 CFR Part 63, Subpart YYYY), GE offers the following information.

GE is not prepared at this time to offer a formaldehyde emissions guarantee pending the outcome of the petition to de-list natural gas fired combustion turbines from the MACT. GE believes that making a commercial guarantee during the MACT de-listing petitioning process may imply industry's support of the MACT standard and could possibly jeopardize the approval of the petition. Such a guarantee may also prompt state and local agencies to require permit limits that would be similar to, or more stringent than, the forthcoming MACT level. Furthermore, EPA has published a "stay" of the MACT rule, as it applies to combustion turbines covered in the de-list petition, which basically excludes such units from compliance with the MACT until the de-listing petition status is approved or rejected by the EPA.

GE has conducted formaldehyde emissions testing on a very limited number of combustion turbines, all of which were Frame 7 DLN units firing natural gas, and in a couple of instances, on distillate oil.

All of the measured formaldehyde levels from our testing are below the MACT standard level of 91 ppbvd at 15% O_2 using CARB Method 430 with modified reporting protocol due to the low level concentrations. The MACT recommends FTIR but allows for other agency-approved methods.

In summary, for the reasons stated above, GE can offer no formaldehyde emissions guarantee for GE Frame 7 DLN units. However, GE expects to meet the 91 ppbvd @ 15% O_2 formaldehyde (HCOH) level on its Frame 7 DLN combustion turbines in normal premix operation on natural gas (without add-on controls). GE expects the same to be true on our Frame 7 units when firing on distillate oil with a water injection rate set to achieve a NOx level of 42 ppm @ 15% O_2 or higher. Please note these statements are based on the condition that emissions testing is conducted using the modified CARB 430 method, or an FTIR designed with proper cell path length and elimination of sample-line interference / off-gassing.

We would be happy to discuss this further with you at any time. Please do not hesitate to contact me if you have any questions.

Best regards,

Jeanne M. Beres

Jeanne M. Beres
Manager – Env. & Acoustic Eng.

cc: F. Brooks
J. Chalfin
J. Almstead

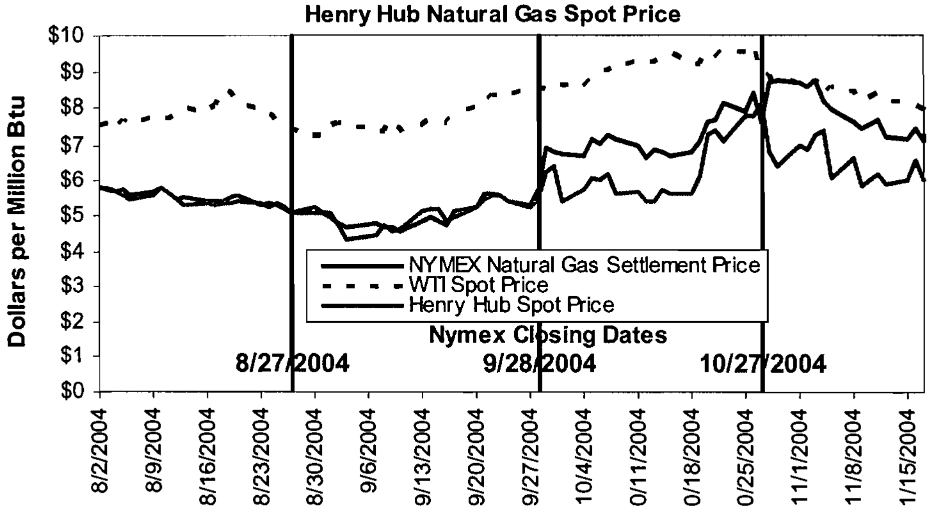
ATTACHMENT 5

Fuel Cost Data
DOE Natural Gas Weekly

Overview: Thursday, November 18 (No issue Thanksgiving week; next release 2:00 p.m. on December 2)

Natural gas spot and futures prices fell for a third consecutive week (Wednesday to Wednesday, November 10-17), as temperatures for most of the nation continued to be moderate to seasonal. At the Henry Hub, the spot price declined 6 cents on the week, for the smallest week-on-week decrease in the nation. Spot gas traded there yesterday (Wednesday, November 17) at $6.06 per MMBtu. Price declines at the majority of market locations ranged from around a dime to nearly 60 cents per MMBtu. On the NYMEX, the price for the near-month natural gas futures contract (for December delivery) fell by almost 40 cents on the week, settling yesterday at $7.283 per MMBtu. EIA reported that working gas inventories in underground storage were 3,321 Bcf as of Friday, November 12, which is 9 percent greater than the previous 5-year average. The spot price for West Texas Intermediate (WTI) crude oil declined for a fourth consecutive week, dropping $1.85 per barrel ($0.32 per MMBtu), or nearly 4 percent, from last Wednesday's level, to trade yesterday at $46.85 per barrel ($8.08 per MMBtu).

NYMEX Natural Gas Futures Near-Month Contract Settlement Price, West Texas Intermediate Crude Oil Spot Price, and Henry Hub Natural Gas Spot Price



Note: The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.
Source: NGI's *Daily Gas Price Index* (http://Intelligencepress.com)

Prices:

Spot prices declined significantly for the week at all market locations, as generally mild weather coupled with the industry's strong inventory position exerted downward pressure on prices. Price declines were largest in the West and Midcontinent and smallest in Gulf coast production areas and the Northeast. In California, high-inventory operational flow orders of varying length and condition imposed by both PG&E and SOCAL, and reports of high linepack on the Kern River Transmission pipeline, underscored the paucity of swing demand, as night-time temperatures in much of the West continue to be well above normal. The average price for Rocky Mountain locations showed the nation's largest drop for the week, at $0.48 per MMBtu, to an average of $5.25 in yesterday's trading. Spot prices at market locations in West Texas fell an average of 42 cents per MMBtu, to the low $5 range, while California points dropped 36 cents, to $5.62 per MMBtu. Thanks to a significant warming trend beginning over the weekend, prices in the Midcontinent declined from 40 to over 60 cents per MMBtu, and ranged between $5.29 and $5.88 per MMBtu in yesterday's trading. Cooler-than-expected temperatures over the weekend in the Northeast and parts of the Mid-Atlantic contributed to increased demand and boosted prices at Gulf Coast supply locations and in the Northeast region on Monday and Tuesday (November 15-16). This partially offset yesterday's large declines, leaving these market areas with smaller week-on-week decreases, which averaged 15 and 17 cents per MMBtu, respectively. The average spot price for Louisiana market locations was $5.98 per MMBtu yesterday, while spot gas for delivery to New York citygates was $6.59.

Spot Prices ($ per MMBtu)	Thur. 11-Nov	Fri. 12-Nov	Mon. 15-Nov	Tue. 16-Nov	Wed. 17-Nov
Henry Hub	6.18	5.89	6.01	6.57	6.05
New York	6.74	6.72	6.77	7.25	6.59
Chicago	6.32	6.02	6.16	6.61	5.86
Cal. Comp. Avg.*	6.01	5.70	5.90	6.29	5.64
Futures ($/MMBtu)					
December delivery	7.236	7.176	7.436	7.124	7.283
January delivery	7.944	7.866	8.047	7.757	7.954

*Avg. of NGI's reported avg. prices for: Malin, PG&E citygate, and Southern California Border Avg.

Source: NGI's Daily Gas Price Index (http://intelligencepress.com).

On the NYMEX, the December contract settlement price declined $0.395 per MMBtu on the week, or just over 5 percent, as the near-month contract settled yesterday at $7.283. This follows the 12 percent decrease during the previous week. Since becoming the near-month contract on October 28, the December contract has fallen 16 percent in value. The futures contracts for delivery in the remaining heating-season months have shown similar declines over the same period (13 to 15 percent). Nevertheless, the basis spread between the Henry Hub spot price and the settlement prices for these contracts continues to be notably large: about $1.23, $1.91, $1.93, and $1.65, respectively, for the December through March contracts as of yesterday. This continues to provide financial incentive for injections into storage, or for limiting withdrawals from storage in favor of spot-market purchases.

Recent Natural Gas Market Data

Estimated Average Wellhead Prices						
	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sept-04
Price ($ per Mcf)	5.20	5.63	5.85	5.60	5.36	4.86
Price ($ per MMBtu)	5.06	5.48	5.69	5.45	5.21	4.73

Note: Prices were converted from $ per Mcf to $ per MMBtu using an average heat content of 1,027 Btu per cubic foot as published in Table A4 of the Annual Energy Review 2002.
Source: Energy Information Administration, Office of Oil and Gas.

Storage:

Natural gas inventories stood at 3,321 Bcf as of Friday, November 12, according to the EIA's *Weekly Natural Gas Storage Report.* **(See Storage Figure)** The net stock change from the previous week was an implied net withdrawal of 6 Bcf, marking the first net withdrawal from storage for the two-week-old heating season. Despite the net decrease in stocks, the inventory surplus over the previous 5-year (1999-2003) average for the week increased to 9 percent, as the week's implied net withdrawal fell short of the 5-year average net withdrawal of 15 Bcf. Net withdrawals were recorded only in the East region, partially offset by small injections in the West and Producing regions. Cooler-than-normal temperatures during the week covered by the storage report in the New England and Middle Atlantic Census divisions, as measured by gas-customer weighted heating degree days (HDD), produced a moderate amount of demand in these areas and contributed to the East's net withdrawal. **(See Temperature Map) (See Deviations Map)** HDDs for these two Census divisions were 24.5 and 17.5 percent, respectively, above normal. Elsewhere, in divisions such as the West North Central, Mountain, and Pacific, HDDs measured 10.7, 13.8, and 2.6 percent, respectively, less than normal. Conversely, parts of West Texas and the Southwest were cooler than normal during the report week, freeing some gas for injections into storage.

All Volumes in Bcf	Current Stocks 11/12/04	One-Week Prior Stocks 11/5/04	Implied Net Change from Last Week	Estimated Prior 5-Year (1999-2003) Average	Percent Difference from 5 Year Average
East Region	1,928	1,939	-11	1,843	4.6%
West Region	425	423	2	372	14.2%
Producing Region	968	965	3	831	16.5%
Total Lower 48	3,321	3,327	-6	3,046	9.0%

Source: Energy Information Administration: Form EIA-912, "Weekly Underground Natural Gas Storage Report," and the Historical Weekly Storage Estimates Database. Row and column sums may not equal totals due to independent rounding.

Other Market Trends:

New Incentives to Help Boost Production in the Gulf of Mexico: In its first 10-year forecast for oil and gas production in the federal waters of the Gulf of Mexico, the Minerals Management Service (MMS) on November 15th said that it expects a 13-percent increase in natural gas production over the next decade. Oil production over the same timeframe will increase by approximately 43 percent, according to the agency. MMS attributed the production increase to new incentives encouraging energy companies to explore and develop difficult-to-reach areas of the Gulf of Mexico. There have been incentive programs for deep-water areas since 2001, and more recent incentives offer developers royalty relief to tap into pockets of natural gas deep under shallow waters in the Gulf. Energy companies are responding positively to the new incentives, according to MMS. By 2011, most oil production in the Gulf likely will come from deep-water wells, while natural gas will come from both the deep-water and shallow-water areas. This is the ninth year of expansion of the deep-water frontier in the Gulf, and this trend is expected to continue over the next 10 years. More than 100 development projects have begun production and new discoveries that have occurred in the past three years are expected to be developed. Natural gas production is expected to increase to 13 billion cubic feet (Bcf) per day by 2011 from current levels of about 12 Bcf per day. However, in the short term, there will be a decline in natural gas production, as old fields begin to be exhausted. This year's production estimate by MMS is based on a new methodology, which analyzes recent deep-water discoveries and projected deep-water reserves in addition to surveying oil and gas companies.

Summary:

Spot and futures prices continued on a downward trend for the third consecutive week, as the lack of significant heating demand and high inventory levels exerted downward price pressure. The basis spreads of futures prices over the Henry Hub spot price continued to be relatively large. EIA reported the first implied net withdrawal of the heating season, as of the week ended Friday, November 12.

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

August 19, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, FL 33701

Re: Request for Additional Information
Hines Energy Complex Power Block 4
File No. 1050234-010-AC

Dear Mr. Zirkle:

The Department is in receipt of your PSD application, however in order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Request for permit revisions

I. Progress has requested permission to operate for up to 3000 hours per year below 60% output, however within Appendix A "Emission Estimates", data was provided for only the 100%, 80% and 60% (65% for distillate) output cases.
   A) Please provide the same data for the 50% 30% and 10% CT output cases for natural gas.
   B) Should Progress desire to be permitted for any operation below 65% CT output while firing distillate oil, then FDEP requires the same data (50%, 30% and 10% output) for the distillate oil cases.
   C) Please indicate the lowest CT output (%) at which continuous operation is sought (on each fuel).
   D) Please provide CT/HRSG/Steam Turbine heat balance diagrams (see attached 'example' from a conventional steam plant) for each of the CT outputs defined above (10%, 30%, 50%, 60%, 80% and 100%)

II. Progress has requested up to eight hours per day of combined excess emissions for a cold start-up and up to five hours of combined excess emissions per day for any steam turbine shutdown. Further, Progress wishes to define a cold start-up as 'following a shutdown of the steam turbine lasting at least 48 hours'.
   A) Based upon prior guidance from EPA Region 4, the Department is not inclined to grant such lengthy time periods for unlimited excess emissions. Instead, the Department will consider the development of alternative emission limits for routine operations where full-load emission limits cannot be achieved (this includes periods such as start-up and shut-downs, and perhaps even extended periods of operation during low load, as has been requested herein). In order for the Department to evaluate alternative emission limits for such operations, actual emission estimates will be required. Therefore, for any pollutant whereby Progress expects to be unable to meet a "full load" BACT established emission limit (but specifically during a steam turbine shutdown and cold start-up), the Department will need to be provided with estimated emission curves during those time periods. This should include each of the stages of the event (e.g. cold startup) including the purpose, operating load, duration at that operating load, and estimated emissions at that operating load.
   B) Please support the (above) proposed definition of a cold start-up ('following a shutdown of the steam turbine lasting at least 48 hours') by providing:
      1) The manufacturers criteria for what constitutes a cold start-up (e.g. turbine manufacturers typically identify the first stage metal temperature on the steam turbine) and
      2) The additional operational measures which the equipment manufacturer requires to be taken as a result of the cold-start-up criteria being met.

III. Within Section 2 of the PSD application, Progress states "At present there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines." In order to be thorough, the Department requests that Progress contact the manufacturer (Siemens Westinghouse) to obtain test data for formaldehyde emissions on 501F machines. Should Westinghouse not have access to any such data, please request that they provide written confirmation to this effect.

IV. Regarding the proposed BACT Determination for CO:

A) Please confirm the evaluated placement position of the oxidation catalyst (within the flue gas stream) for Hines Power Block 4 is directly after the CT (and before the HRSG), as suggested in Appendix B, page 14. If this is not the desired placement, please specify the position in the flue gas stream as precisely as possible.

B) The Department notes the following discrepancies between the provided cost effectiveness calculation and the OAQPS Control Cost Manual:

1) Indirect Costs are to be based upon a percentage of the Direct Capital Costs (TDCC in your supplied calculation), exclusive of the Direct Installation Costs (TDIC). The submitted evaluation shows indirect costs as based upon the sum of TDCC and TDIC (referred to as Total Capital Costs).
2) The "Inventory Cost" associated with the Catalyst Replacement Cost is not an acceptable entry.
3) The Capital Recovery (referred to as Annualized Total Direct Capital in the submitted evaluation) should **exclude** the initial cost of the catalyst (times freight and sales tax).
4) Heat Rate Penalty – Please provide the Department with the assumed fuel cost (in $/MMBtu) which was utilized as a basis for adding $3/MMBtu in the "Heat Rate Penalty" calculation.

C) Please provide the basis for the estimated TPY of CO removed which was utilized in the submitted cost effectiveness of $3,773 per ton

D) Please provide the basis for the estimated net TPY emission reduction, which was utilized in the submitted cost effectiveness of $4,070 per ton

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin

Michael P. Halpin, P.E.
DARM/BAR
North Permitting Section

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

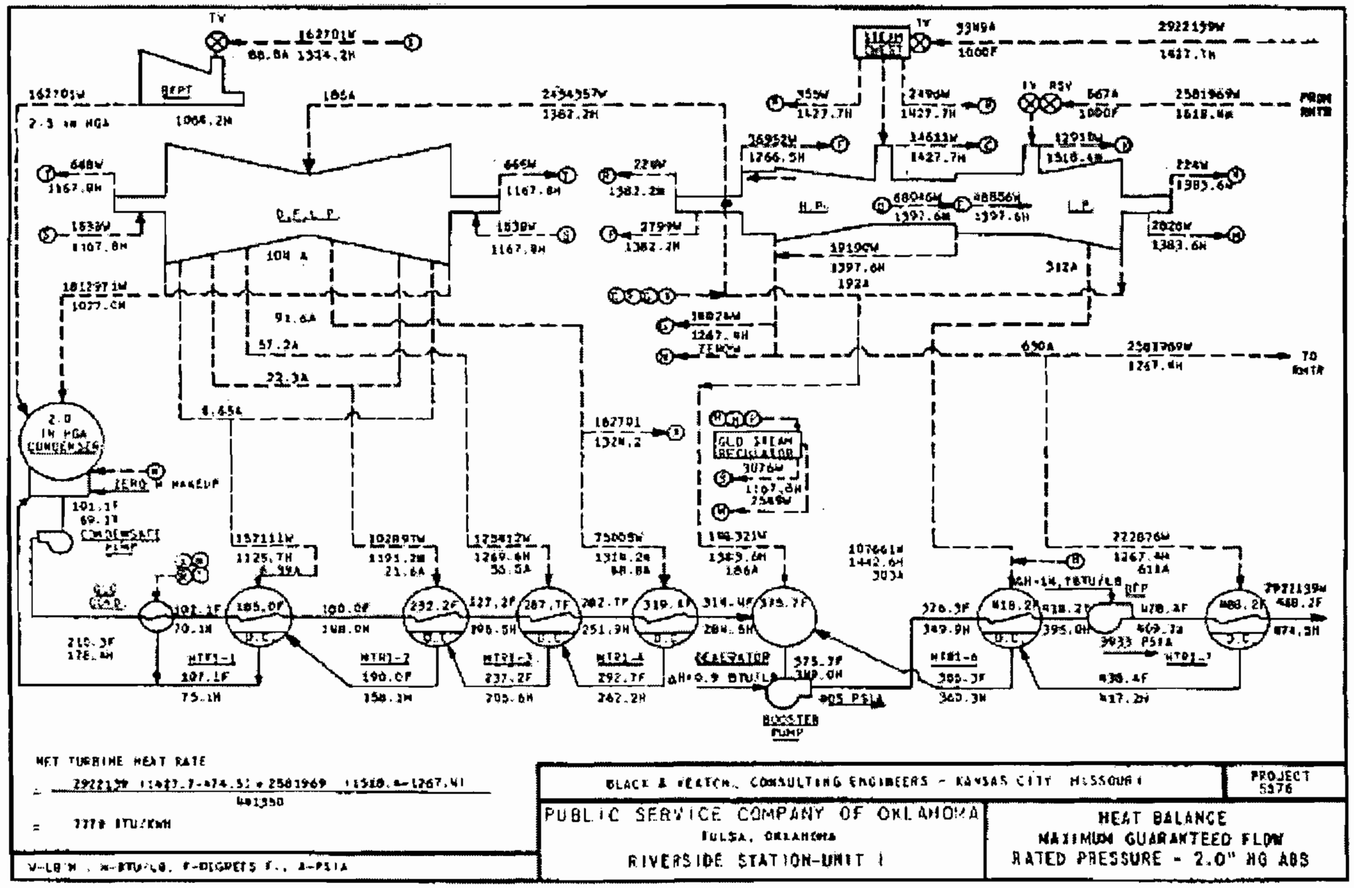


FIGURE 2.13 Thermodynamic properties and flow rates in a modern natural-gas-burning steam power plant—PSO Riverside Station Unit #1. (Courtesy of Public Service Company of Oklahoma.)

DEP File No. 105234-010-AC

SENDER: COMPLETE THIS SECTION

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1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, Florida 33701

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 8/25

C. Signature

X ☐ Agent ☐ Addressee

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Mr. Roger Zirkle, Plant Manager

Street, Apt. No.; or PO Box No. 100 Central Avenue

City, State, ZIP+ 4 St. Petersburg, Florida 33701

PS Form 3800, January 2001 See Reverse for Instructions

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

August 13, 2004

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
12795 W. Alameda Parkway
Lakewood, Colorado 80228

RE: Progress Energy Florida
Hines Energy Complex, Power Block 4
1050234-010-AC, PSD-FL-342

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Progress Energy Florida to construct Power Block 4 at the Hines Energy Complex in Polk County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams

for James K. Pennington, P.E.
Administrator
North Permitting Section

JKP/pa

Enclosure

cc: M. Halpin

SENDER: *COMPLETE THIS SECTION*

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1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida
100 Central Avenue
St. Petersburg, Florida 33701

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B. Date of Delivery 8/25

C. Signature

X ☐ Agent ☐ Addressee

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City, State, ZIP+4 St. Petersburg, Florida 33701

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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

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A. Signature X ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) C. Date of Delivery

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JAN 20 2005
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4. Restricted Delivery? (*Extra Fee*) ☐ Yes

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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
Street, Apt. No.; or PO Box No.
Complex
City, State, ZIP+4
~~P.O. Box 14042, MAC BB1A~~
St. Petersburg, Florida 33733-4042

PS Form 3800, May 2000 See Reverse for Instructions

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1. Article Addressed to:
Mr. Jammie Hunter
Progress Energy Florida
Hines Energy Complex
Post Office Box 14042, MAC BB1A
St. Petersburg, Fl 33733-4042

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

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Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To
Mr. Jammie Hunter
Progress Energy Florida
Street, Apt. No.; or PO Box No.
P.O. Box 14042, MAC BBIA
City, State, ZIP+4
St. Petersburg, Fl 33733-4042

PS Form 3800, May 2000 See Reverse for Instructions

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1. Article Addressed to:

Mr. Jamie Hunter
Progress Energy Florida
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X MW ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) C. Date of Delivery

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

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JUN 15 2005
CUSTOMER SERVICE

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Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. Jamie Hunter
Progress Energy Florida
Post Office Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

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1. Article Addressed to:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida-Hines Energy Complex
100 Central Avenue, CX1B
St. Petersburg, Florida 33701

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ ~~Agent~~ ☐ Addressee

B. Received by (Printed Name) M. A. McLou C. Date of Delivery 6/15/05

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

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Mr. Roger Zirkle, Plant Manager
Progress Energy Florida-Hines Energy Complex
100 Central Avenue, CX1B
St. Petersburg, Florida 33701

PS Form 3800, January 2001 See Reverse for Instructions

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

August 13, 2004

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Progress Energy Florida
Hines Energy Complex, Power Block 4
1050234-010-AC, PSD-FL-342

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Progress Energy Florida to construct Power Block 4 at the Hines Energy Complex in Polk County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams

for James K. Pennington, P.E.
Administrator
North Permitting Section

JKP/pa

Enclosure

cc: M. Halpin

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No ....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared C. Morgan Miller, who on oath says that he is Display Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being an

Public Notice of Intent

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in the matter **Hines Energy Complex at Power Block 4**.....................

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Concerning **Project No. 1050234-010-AC** ....

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was published in said newspaper in the issues of **2-2; 2005**................

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Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed......C. Morgan Miller..........
C. Morgan Miller
Display Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 2nd ....

day of February .... A.D. 20 05 ....

....Patricia Ann Rouse.....
Notary Public

(Seal) PATRICIA ANN ROUSE
MY COMMISSION # DD 330015
EXPIRES: October 17, 2008
Bonded Thru Notary Public Underwriters

My Commission Expires......Oct 17, 2008......

M119

Attach Ad Here

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 7miles south-southwest of Bartow and 5miles west-northwest of Fort Meade.

Project: The existing Hines Energy Complex currently consists of two operating electrical generating units (Power Blocks1 and 2) and another electrical generating unit currently under construction (Power Block3). Power Block1 is a 500MW 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 Block3, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530MW power generation unit. After completion of this project (Power Block4), the plant will have a total generating capacity of approximately 2,090MW.
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.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the project file is available at the Air Resource Section of the Department's Southwest District Office at 3804 Cocanut Palm Drive, Tampa, Florida 33619-8218 (Phone: 813/744-6100).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate 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.

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 e-mail 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 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 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.

M119 2-2; 2005